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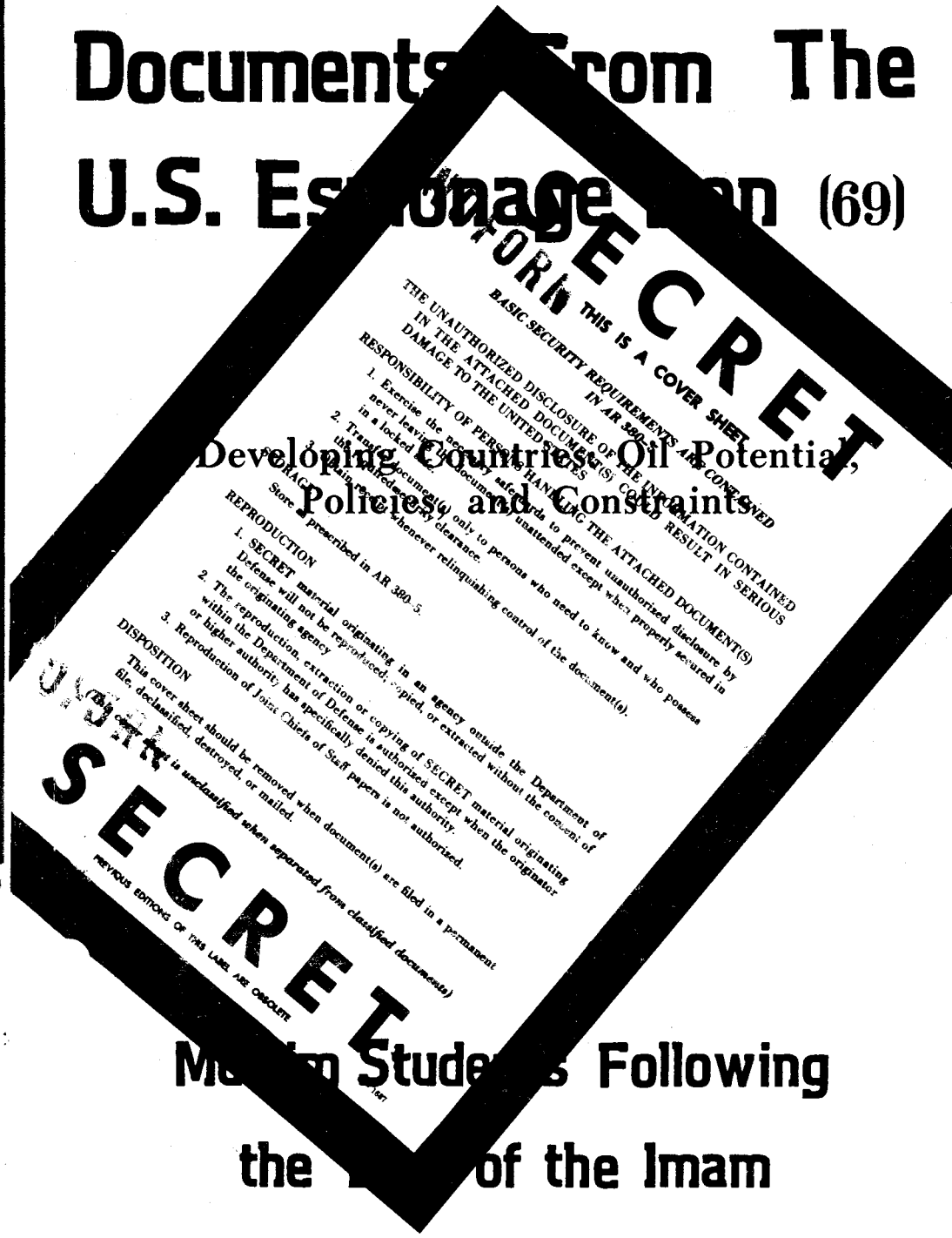

Developing Countries' Oil Potential, Policies, and Constraints

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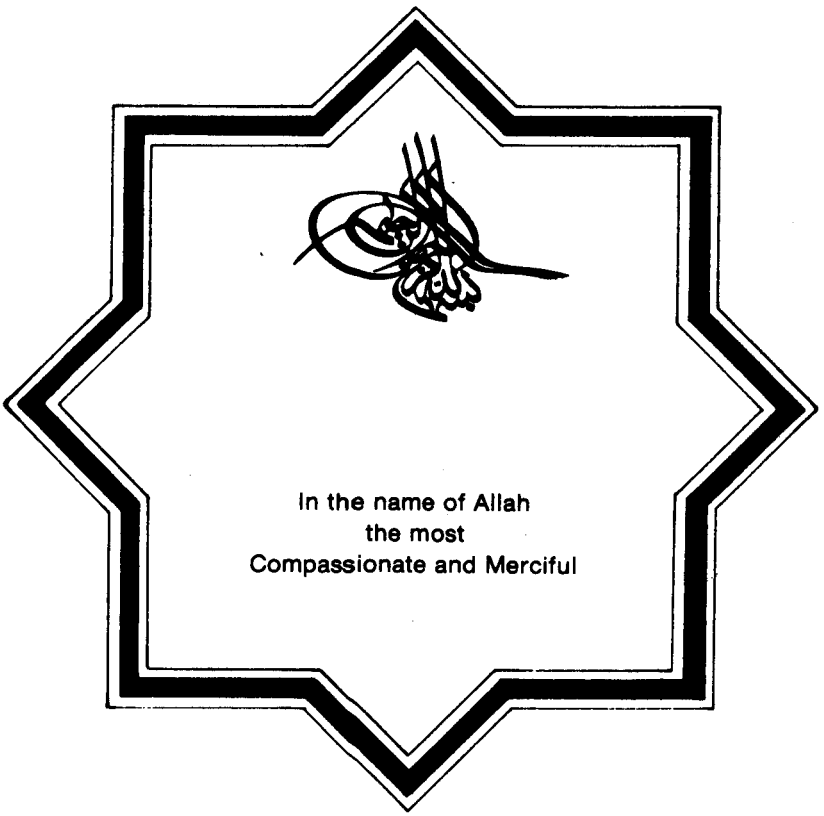

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the most
Compassionate and Merciful

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Developing Countries: Oil Potential, Policies, and Constraints

Central Intelligence Agency
National Foreign Assessment Center

November 1977

Overview

The likelihood of petroleum supply shortages beginning in the early to mid-1980s has heightened interest in the oil potential of less developed countries (LDCs). Basically this potential depends on geological factors which determine the reserve base of an individual country. Identifying and developing the reserve base, however, depend on a variety of factors including government policies toward foreign oil companies, technical limitations of state-owned oil companies, financial constraints, and in some instances, territorial disputes which impair access to promising areas. This report evaluates the oil potential of 40 developing countries—including those OPEC members outside the Middle East and North Africa—with these factors in mind.

The Resource Base

For most LDCs, the oil reserve base itself is too small to support oil production—large reserves are known to exist in only a handful of countries. In the Western Hemisphere, Mexico with 25 billion barrels of proved and probable reserves is by far the leader, followed by Venezuela with 14 billion barrels. Sub-Saharan Africa is dominated by Nigeria with 19 billion barrels. Among other countries in the area, only Angola and Gabon have reserves of as much as 1 billion barrels. The leaders of the non-OPEC Middle East are Oman with 6 billion barrels and Egypt with 4 billion barrels; no other country in the area comes even close. In South and East Asia, Indonesia has 14 billion barrels, while Brunei, Malaysia, and India have about 2 billion barrels each.

With adequate exploration, prospects are reasonably good for expanding the reserve base of countries that already have fairly extensive reserves. Locating fields of Middle East size, however, appears possible only in Mexico and perhaps on the Argentine continental shelf. Other areas with good—albeit substantially smaller—potential include eastern Peru, Ecuador, Egypt, India, and those producing countries bordering the South China Sea. In some countries—notably Venezuela, Nigeria and Indonesia—substantial exploratory work is needed just to keep the present reserve base from declining.

Geological prospects elsewhere in the developing countries are uncertain at best. Considerably more exploration is required even to identify areas with geological conditions favorable to finding oil. Basically unsurveyed areas with some potential include Pakistan's Baluchistan Basin, the Bay of Bengal, and the Adaman Islands. The East African coast, particularly along Somalia, has also been left largely untouched. More work is also needed to prove potential in the offshore and Amazon areas of Brazil, in offshore areas of western Africa, between Ivory Coast and Angola and in the waters of the South China Sea.

Foreign Participation

Developing even the known potential has been hampered in some instances by government policies toward the international oil companies. Unduely harsh terms, unilateral changes in contracts, and nationalizations have often characterized past company-country relations in the Third World.

State oil companies exist in almost all developing nations. These companies are not in themselves a hindrance to oil exploration and development. Indeed, some state companies—that of Egypt is a good example—have excellent relations with the foreign firms. Other state companies are little more than government departments faithfully reflecting the attitudes of the regimes they serve. Still others, however, are bastions of nationalism and would rather see the oil left in the ground than produced with foreign help.

Few, if any, state oil companies have the technical and managerial skills to explore in the offshore areas and deep formations where most new oil is found. Only the best of the state companies, Mexico's Pemex, is capable of finding and producing oil, even in difficult areas; the speed and efficiency of development is limited, however, to the extent that Pemex sticks to its "go-it-alone" credo. Other generally competent state companies, including those of Argentina, Brazil, India, and Egypt, lack the ability to find and produce oil in difficult locations without foreign help. Despite these limitations, many state companies have reserved the best areas for themselves while establishing relatively harsh terms for foreign participation in higher risk operations.

Liberal operating guidelines do not assure company interest unless geological prospects indicate sizable reserves. Major oil companies, for example, have devoted few resources to exploration in many sub-Saharan countries with limited oil potential. In several countries with domestic oil consumption of less than 10,000 b/d each—notably the Ivory Coast, Chad, Zaire, and Congo—finding and developing even a small reserve base could go a long way toward meeting these needs. One constraint in going this route would be the necessity for regional refineries to process small amounts of crude. In any event, oil companies have tended to lose interest in exploration because key potential reserves are too small to support more sizable production levels.

Financing and Equipment

Countries with sizable proven oil potential have little trouble obtaining needed funds. Mexico faced some constraints earlier this year as a result of foreign borrowing limits imposed by the International Monetary Fund (IMF), but these controls may be relaxed on oil-related borrowing. A few small-scale producers—Pakistan, for example—have also run into problems obtaining funds for exploration equipment purchases in the West. India may eventually face a similar difficulty. In these instances, however, the basic problem is the host government's reluctance to induce foreign oil companies to enter the area. West African countries such as Ivory Coast, Cameroon, Chad, and Congo would face financial as well as technical problems if they attempted to sustain an exploration effort in the event of a foreign company pullout.

At present, the availability of rigs and other equipment is not a major constraint. Temporary bottlenecks might arise if extensive exploration programs were simultaneously undertaken in several areas of the world; such bottlenecks could probably be eliminated in a one- to two-year period. A much greater constraint is the shortage of experienced personnel at all levels. Despite the high international mobility of oil workers and technicians—a factor that helps make most efficient use of such labor—this constraint is likely to persist for at least the next decade.

Territorial Issues

Territorial disputes are impeding exploration of numerous promising areas. Conflicting territorial claims, for example, have all but hamstrung offshore operations in the South China Sea and

off South Korea. Boundary disputes are also interfering with work in high-potential offshore areas claimed by Tunisia and Libya. Conflicting Greek-Turkish claims have prevented oil company operations in their offshore areas as well; Argentine-British claims to the Falkland Islands will become a problem if large oil deposits are located in that area. In the Gulf of Suez, Israeli harassment of oil company operations has already slowed development of sizable known reserves.

The Production Outlook

Given the present pace of exploration and development we expect oil production in non-OPEC LDCs as a group to reach 6 million b/d by 1980 and range from 8 million to 9 million b/d in 1985. These projections are based on development efforts already in prospect and mainly reflect expected production gains in Mexico, Egypt, and India.

Selected LDCs: Oil Potential

Country	Prospects for Increasing Reserves	Operating Climate	Remarks
Latin America			
Argentina	Good to excellent	Good to fair	Territorial dispute with UK
Belize	Fair to poor	Fair to good	Territorial dispute with Guatemala
Bolivia	Good to fair	Good	Continued small additions to reserves likely
Brazil	Good to fair	Fair to good	Operating climate improving
Chile	Fair	Good to fair	Additional small finds possible
Colombia	Fair	Fair to good	Best prospects are for gas on north coast
Ecuador	Fair to good	Fair to good	More exploration needed in eastern area
Guatemala	Fair to good	Fair	Not a real winner, but some increase in reserves likely
Mexico	Excellent	Good	Good prospects for Middle East - sized discoveries
Paraguay	Fair	Good	Favorable geology, but poor exploration results
Peru	Good to fair	Fair to good	More exploration needed in trans-Andean area and offshore
Uruguay	Poor	Good to fair	Exploration failures dim prospects
Venezuela	Fair to good	Fair to good	Much explored, but good prospects remain
Other	Poor	Good to fair	Few possibilities outside Trinidad and Central America
Asia and Pacific			
Bangladesh	Poor	Good to fair	Gas prospects promising; territorial disputes
Brunei	Good to fair	Excellent	Good prospects for additional offshore discoveries
Burma	Fair to good	Fair	Small additions to onshore reserves likely; some offshore potential
India	Good	Good to fair	Another "Bombay High" is not out of the question
Indonesia	Good	Good	Discovery rates continue strong
Malaysia	Good to fair	Fair	More exploration needed in several areas
Pakistan	Fair	Good to fair	Major basin unexplored
Philippines	Fair to good	Good	Offshore potential; territorial disputes
South Korea	Fair	Fair to good	Territorial disputes
Taiwan	Poor to fair	Good to fair	Gas prospects good; territorial disputes
Thailand	Poor	Good	Good gas prospects
Vietnam	Fair to good	Fair to poor	Noncommercial finds indicate some potential
Other	Poor	Good to poor	

Country	Prospects for Increasing Reserves	Operating Climate	Remarks
Non-OPEC Middle East, North Africa, and the Mediterranean			
Egypt	Good to excellent	Good	Dispute with Israel slows exploration
Greece	Fair to poor	Fair	Territorial dispute with Turkey
Jordan	Poor	Good to excellent	West Bank may hold some potential
Oman	Good to fair	Good	Discovery of more small, high-cost fields likely
Syria	Fair	Fair	Best prospects offshore
Tunisia	Good to fair	Good to fair	Territorial dispute with Libya
Turkey	Fair	Fair	Offshore areas hold some promise
Other	Poor	Good to fair	Israel and Lebanon hold little potential
Sub-Saharan Africa			
Angola	Good to fair	Poor to fair	No increase in exploration likely until political situation clarifies
Cameroon	Good	Good to fair	Small additions to reserves almost certain
Chad	Good	Good to fair	Expensive pipeline needed to get oil out
Congo	Fair to poor	Good to fair	Any additions to reserves will probably be small
Gabon	Fair to poor	Good to fair	Any additions to reserves will probably be small
Ivory Coast	Fair to good	Good to fair	Noncommercial finds may presage larger discoveries
Nigeria	Good	Fair to good	Many more small fields likely to be discovered
Zaire	Fair to poor	Good to fair	Any additions to reserves will probably be small
Other	Poor	Good to poor	The East African coast from Sudan to Somalia and the Gulf of Guinea area west of Nigeria have some potential

Latin America

The Western Hemisphere offers the best prospects for finding large new oil reserves among non-OPEC LDCs. Mexico's Reforma Fields, when fully explored, will almost certainly prove to be of Middle East size. Work in this area is proceeding rapidly, although even more progress would be possible if financial and political restraints could be overcome. The sedimentary basins between Argentina and the Falkland Islands, as yet undrilled, also appear to have great potential. Difficult operating conditions, doubts as to the permanence of Argentine oil policy, and the UK-Argentine dispute over ownership of the Falkland Islands are inhibiting exploration in this area. Elsewhere in Latin America prospects for additional finds—most of which would be relatively small—are good off the mouths of the Orinoco and the Amazon, in trans-Andean Peru, Ecuador, and Bolivia, and offshore Brazil. Exploration is presently limited in most of these areas by past failures and, in some cases, nationalistic government policies.

South Mexico, Guatemala and Belize: Oil and Gas Prospects

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MEXICO

Among non-OPEC LDCs, Mexico has the brightest prospects for substantially increasing petroleum output. President Lopez Portillo and his chief advisers are convinced that increased petroleum and natural gas exports are necessary and have approved an ambitious investment program for Pemex, the state oil company. The reserve base itself is large and promises to increase sharply as new discoveries are made. Pemex is rapidly developing this potential; an even more rapid development is possible if financial constraints can be overcome and if Lopez Portillo undertakes an all-out effort.

Geological Prospects

In 1972 Mexico discovered the vast Reforma oil deposits in the southeastern states of Tabasco and Chiapas. Mexican officials now believe that these onshore fields link up with recent offshore oil discoveries at Chac 160 kilometers to the north, forming a vast producing area that could rival the largest Saudi Arabian fields in size. Using industry definitions, we currently estimate proved and probable onshore reserves in the Reforma area at 25 billion barrels. Potential petroleum reserves could prove to be many times this amount when fully evaluated by drilling. Reforma oil is a high-quality, medium-sulfur (1.6 percent by weight), 28° to 30° API gravity oil. Reforma Fields also contain vast amounts of associated natural gas, yielding an average of 1,300 cubic feet of gas per barrel of oil.

Historically, exploration efforts have been concentrated in the Gulf of Mexico coastal plains area. Oil was discovered well before 1900 in very shallow formations in the states of Tamaulipas and Veracruz. Mexico's extensive "Golden Lane" Fields, discovered in 1910, and the rich Poza Rica Fields, discovered in 1930, were among the most important oil finds of their time. In recent years Pemex has greatly increased exploration in other regions, and officials claim only about 10 percent of the potential oil-bearing areas have been explored. Substantial gas deposits have been recently found in northern Mexico between Nuevo Laredo and Monclova, and some promising oil wells have been drilled in new areas of Veracruz state. Offshore Baja California also has substantial hydrocarbon potential.

Pemex has the technological know-how and trained personnel to handle all phases of oil industry operations. Its engineers are acknowledged experts in the completion of wells in carbonate deposits. Mexico is beginning to patent its inventions, especially in the refining area, and is supplying technical assistance to other countries. US firms continue to provide much of the equipment and technology used by Pemex, but Pemex personnel perform all tasks competently. Jorge Diaz Serrano, since his appointment by Lopez Portillo as Director General of Pemex, has further beefed up the company's efficiency.

At present it appears that Mexico will be able to obtain the funds necessary to carry out the Pemex development program. The six-year plan calls for doubling the average investment outlays of the past two years to $2.5 billion per year. A gas pipeline from the Reforma area to the United States will cost an additional $1.5 billion. The sharp rise in oil-related spending has already pushed the Pemex foreign debt to $2.4 billion, up from $1.25 billion last year. Although its commercial credit rating remains good, credit is getting tighter. Pemex estimates it will need to obtain half of its investment funds from foreign sources.

Pemex's $15.1 billion development plan (1977-82) is well within the company's technical capabilities. It seeks to raise daily production by 1982

to 2.2 million barrels of oil and 3.6 billion cubic feet of gas. The development program allots $1 billion for preliminary exploration, $4 billion for drilling, $3.2 billion for production, and the remaining $6.9 billion for refining, petrochemical production, marketing, and transportation. The drilling plan calls for 2,100 development wells and 1,300 wildcat operations, including 477 development wells in Tabasco and Chiapas and 24 exploration wells and 120 development wells on the Campeche continental shelf. The production plan involves intensified primary exploitation in areas already producing, secondary recovery, and the development of offshore fields.

Outlook

If a more active development program is adopted and sufficient foreign funds are available, Mexico could do even better than called for in the plan. Production could reach 2.2 million b/d in 1980 and more than 3.5 million b/d in 1982. This would allow oil exports of 1.2 million b/d in 1980 and 2.2 million b/d by 1982. Whatever the output path, the Reforma Fields will continue to account for the major share of production. Drilling success rates have been extraordinary in these fields, with less than 15 percent of the wells dry or noncommercial.

In addition to the development plan Mexico will move ahead with plans for $1.5 billion, 48-inch pipeline to move natural gas 1,200 kilometers from the Reforma area to the US border. The pipeline is to run from Cactus, Chiapas up the coast to Reynosa. Construction, once begun, will take two to three years to complete. Although the eventual capacity of the line will be 2.7 billion cubic feet per day, Mexico will initially ship only 1 billion cubic feet per day; by 1982 this will rise to 2 billion cubic feet per day. Domestic users will receive the remaining 0.7 billion.

Although Lopez Portillo appears interested in cooperation in the energy field, he has made it clear that such cooperation must take into account Mexican sensitivities and cannot prejudice full Mexican control over resource development. Because of Mexico's bias against foreign oil companies, production-sharing agreements are out of the question even if this means slower than optimal development of the reserve potential.

ARGENTINA

Argentina has an excellent chance of expanding reserves to many times the present 2.5 billion barrels. Its 2.6-million-square-kilometer continental shelf—four times as large as the US Atlantic shelf—is one of the most promising unexplored areas in the world. Although exploration has barely begun, the region's geology suggests huge deposits. Onshore reserves also are probably much greater than those now known.

Geological Prospects

The Argentine continental shelf may contain very large oil reserves. According to a 1974 US Geological Survey estimate based on preliminary findings, the shelf may have as much as 200 billion barrels of oil—80 times present Argentine proved reserves and more than double proved reserves in the Western Hemisphere. The government has engaged two US companies—Geophysical Service, Incorporated, and Western Geophysical Company—to conduct geological and seismic research on the continental shelf. Final results, however, will not be available for some time.

Of the eight main offshore sedimentary basins, two—the San Jorge and Austral (Magellan)—are extensions of important onshore producing areas. The Malvinas Basin, adjacent to the Austral, is considered by some experts to be especially promising, but exploration there has barely begun, in part because the basin lies in disputed territory between the Argentine mainland and the Argentine-claimed, British-administered Falkland Islands. British surveys downplay the oil potential of the area, perhaps for political reasons. Other possible, but less promising, areas near the Falklands—the Burdwood Bank, the Falkland Plateau, and the San Jorge Basin—are subject to similar considerations.

Other offshore areas are more easily explored, and operations have already begun in the Colorado Basin off Bahia Blanca. Early this year, the state-owned oil company, Yacimientos Petroliferos Fiscales (YPF), started drilling there, using a rig purchased from France. The first well, already completed, proved barren, but a second reportedly has struck oil-bearing rock. A third is planned.

Onshore exploration is being stepped up throughout Argentina. All provinces in the southern half of the country, and Salta and Jujuy Provinces in the northwest, now produce oil. Mendoza, in west-central Argentina, is the leading province, followed by Chubut, Santa Cruz, and Rio Negro farther to the south. Most fields are small. A major new field was discovered in 1975 in Mendoza Province, and several new finds have been reported this year in Salta, Neuquen, Mendoza, Santa Cruz, and Chubut Provinces.

Proved reserves have remained nearly static for the past few years at a level that could support the 1976 output of about 400,000 b/d for 17 years but is far short of the amount needed to achieve the government goal of oil self-sufficiency by the mid-1980s. Present output meets 85 to 90 percent of requirements.

Capabilities and Constraints

Government economists estimate that the Argentine oil expansion program will require investment of $15 billion to $20 billion over the next 10 years. Since the government cannot finance such a sum itself, it is making private—especially foreign—participation an integral part of the program, reversing the nationalistic policies of preceding governments. The junta's new foreign investment law is intended to encourage foreign investors by reducing red tape and assuring that capital and profits can be repatriated. Most foreign companies are waiting, however, to see whether economic and political conditions remain stable.

Northwest South America: Oil and Gas Prospects

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VENEZUELA

Venezuela's prospects for finding large, new conventional oil deposits are bleak. With proved and probable reserves of 14 billion barrels, oil production is expected to stagnate through 1980 causing Caracas to lose its place as the world's fifth largest oil producer. Moreover, output will begin to fall sharply in the mid-1980s as existing fields near exhaustion. Although unexplored areas with oil potential lie offshore on the continental shelf, Caracas has effectively undercut any interest on the part of major oil companies as a result of its nationalization policies. Large reserves of heavy oil exist in the Orinoco Tar Belt, but with existing technology only a small fraction can be recovered and that at very high costs.

Geological Prospects

Venezuela's first major commercial oil discovery occurred in 1914, three years after exploration began. Since then, production has been concentrated in and around Lake Maracaibo, particularly in the Bolivar Coastal Field, the world's fourth largest field. It was discovered in 1917 and remains Venezuela's chief source of oil production at 1.5 million b/d. Other producing areas are in eastern Venezuela in the Maturin Basin, stretching from Guarico state to the Atlantic coast, in the south in Barinas and in the north in Falcon.

Exploration efforts have been minimal in recent years, causing proved and probable reserves to fall from 17.4 billion barrels in 1960 to 14 billion in 1976. Prior to the 1976 nationalization, increasingly nationalistic policies restricted exploration by foreign oil firms to their concession areas or to service-contract areas in southern Lake Maracaibo. The Venezuelan Petroleum Corporation (CVP), the state oil company, was charged with exploration in other areas but lacked sufficient funds and expertise to conduct major exploration efforts.

Since nationalization, exploration has not picked up. In 1976 the new national holding company, Petroleos de Venezuela, concentrated its 39 exploratory wells in the Maracaibo and Falcon Basins. Three new field wildcats were drilled: two were dry and one drilled to 1,500 meters in the Falcon Basin produced 1,126 b/d of 22° API oil. The others were new pool wildcats, with 21 producers and 15 dry wells. This year, 57 exploratory wells are planned. Petroleos plans to expand exploration as part of increasing investment outlays from $0.8 billion in 1977 to $1.6 billion annually during the period 1978-80. By 1980, Venezuelan plans call for adding about 1.5 billion barrels to net reserves.

Venezuela's best medium-term prospects are offshore; particularly off the Orinoco River Delta; along the Caribbean continental shelf, particularly in the Gulf of Triste, in the Gulf of Coro, and—upon settlement of the border dispute with Colombia—in the Gulf of Venezuela. A longer term possibility is the Orinoco Tar Belt. According to the government, the initial results of its small seismic and drilling program raised gravity estimates to a still very low 8° to 10° API and possible reserves to 3 trillion barrels. With present technology, about 10 percent can be recovered. Higher recovery rates require overcoming problems in extracting the heavy oil and reducing metallic and sulfur content.

Capabilities and Constraints

The primary constraints on increasing Venezuelan production include the limited size of the nation's reserves, the conservationist ethic dominating oil policy, the nationalized industry's limited capability to carry out a major exploration program, and the government's unwillingness to expand the role of major oil firms beyond current marketing and technical assistance con-

tracts. Additionally, the border dispute with Colombia over the boundary in the Gulf of Venezuela is preventing exploration of that promising area. The discovery of oil on the continental shelf near undefined borders with the Netherlands Antilles or Trinidad and Tobago could cause border disputes, thus slowing development.

Caracas' limited technical capacity is preventing significant exploration programs, development of the sophisticated technology required to exploit the heavy oils in the Orinoco Tar Belt, and maintenance of productive capacity. Participation by foreign oil firms must increase if major programs are to begin in earnest. Concern over maintaining political and economic independence and the political tensions arising from a heated presidential election campaign will prevent Caracas from seeking an expanded foreign role before 1979, however.

Costs of major exploration and development efforts needed to boost reserves to Caracas' 1980 target of 15.5 billion barrels would probably exceed planned outlays. Venezuelan planners apparently used 1974 industry cost estimates for finding and developing oil in Latin America in estimating the cost of their program. Planned exploration and development expenditures of $3 billion do not take into consideration the high cost of drilling offshore or new deep onshore wells. Even with its current high oil income, Venezuela would need overseas financing to carry out a large program.

Outlook

Political and manpower constraints are likely to prevent Venezuela from carrying out a major exploration effort in the next few years, and production will probably remain near current levels of 2.3 million b/d through 1980. Over the longer term, as oil production from the depleted oilfields begins to fall, Caracas may become more willing to consider increased foreign participation. With a major exploration effort, discoveries in promising offshore structures might stem the decline in Venezuela's oil reserves for a time.

PERU

Low discovery rates in the face of brisk exploration in recent years have deflated Peru's expectations of OPEC-sized oil production and exports. Despite the collapse of the massive Amazon Basin exploration campaign of 1974 and 1975, new discoveries will provide a small surplus for export. Gradually rising output from the Amazon will be moved to the coast along with expensive new Trans-Andean Pipeline (see map, page 8). This should augment production from the older fields onshore and offshore in northwest Peru, hiking oil output from 77,000 b/d in 1976 to about 200,000 b/d by 1980. Even with future oil finds offshore as well as in unexplored areas of the Amazon Basin, Peru will be able to export only small amounts of oil through the 1980s.

Geological Prospects

Until the early 1960s, Peruvian oil activities centered near Talara on the northwest coast of Peru. The onshore oilfields surrounding Talara are among the oldest in the Western Hemisphere with almost 100 years of commercial operations. These fields were owned and operated by the US International Petroleum Company until they were expropriated in 1968 and turned over to the newly formed state oil company, Petroperu. Having been extensively explored, the onshore area near Talara will not likely reveal any large new reserves.

Geologists believe the potential of the adjacent offshore areas to be high. Belco Petroleum, a US firm, began offshore exploration near Talara in 1960 and is currently producing more than 30,000 b/d. In May 1977 Belco announced a promising discovery north of previous operations—a well capable of producing 2,000 b/d of 36° API oil with low sulphur content. More exploratory wells are planned in the same area later this year.

The exploration emphasis of the 1970s has been inland, in the vast upper Amazon Basin in northeast Peru. This region was considered highly promising because of its proximity to major discoveries in Ecuador. In November 1971 Petroperu struck oil with its first well. Twelve strikes soon followed with average APIs in the high 20s and flow rates of 3,000 b/d. Following Petroperu's strikes Occidental Petroleum Company, beginning in October 1972, drilled 10 consecutive commercial wells in the jungle just south of Ecuador. Occidental's oil has APIs in the mid-30s, low sulphur content, and potential flow rates of 3,400 b/d. This early success caused a rush to the jungle and, by 1974, 18 companies or groups were exploring an area of some 260,000 square kilometers. Subsequent oil discoveries, however, by Union Oil, Amoco, Phillips, and Hispanoil were heavy and noncommercial. Failure to locate additional commercial reserves has produced a rapid exodus from the jungle of all the contractors except Occidental.

Recent completion of the Trans-Andean Pipeline enhances prospects for exploration and development in the still largely unexplored Amazon jungle. The $670 million pipeline—moving oil from the Amazon Basin to the Pacific port of Bayovar—began operations in May 1977. With the completion in mid-1978 of the $130 million Occidental feeder pipeline, jungle deliveries should increase from the present 40,000 b/d to about 100,000 b/d. By 1980, output from already proved reserves will peak at about 130,000 b/d.

Capabilities and Constraints

Although Petroperu has increased its technical and managerial skills since 1968, its capability is limited to onshore drilling. Moreover, the state company has been plagued by cash flow shortages and a limited debt service capability. Fi-

nancing of the $800 million Trans-Andean Pipeline system, which largely was arranged in the heady days of the jungle boom, pushed Petroperu to its debt management limit, leaving little to finance oil exploration.

To help speed exploration of the vast jungle, beginning in 1971 Petroperu negotiated 18 production-sharing contracts with international oil companies of about 10,000 square kilometers each in the Pastaza-Maranon Basin before closing Peru to new contracts in 1973. The contracts set up strict operating conditions and required giving Petroperu 50 to 56 percent of all oil produced. The contracts assigned exploration and exploitation rights for 35 years, stipulated rigid drilling schedules, and required half of the assigned area to be turned over to Petroperu after seven years. Most of the contractors who abandoned Peru during the last two years failed to complete scheduled drillings, preferring to pay a $1 million to $2 million penalty instead of absorbing the cost of other dry wells.

Outlook

Chances of attracting new exploration by foreign firms were dealt a severe blow by the bad experience in the Amazon Basin. Although Lima has offered to negotiate a new set of contracts for the jungle and continental shelf, no firm offers have yet been made. The Peruvian Government has responded to the lukewarm response by sweetening its proposals with more attractive and flexible terms. To date only one international oil company is reported to have signed a preliminary agreement. Even with renewed participation by foreign oil firms Peru will be at best only a small exporter in the near future. By 1980 total oil production, including output from the Amazon and Talara areas, will approximate 200,000 b/d, leaving an exportable surplus of only 30,000 b/d.

ECUADOR

Given adequate exploration, Ecuador might add 1 billion to 1.5 billion barrels to its present proved and probable reserves of 1.7 billion barrels. The pace of search will be slow, however, unless the government is able to attract extensive foreign participation.

Geological Prospects

Ecuadorean oil production from western Santa Elena Peninsula began in 1911. Exploration has been undertaken in the Oriente since 1937, but extensive efforts began only after the 1967 discovery of the Lago Agrio deposit by a Texaco-Gulf consortium. Between 1967 and 1971, the consortium uncovered in Napo Province Ecuador's five major producing fields (see map, page 8). Several smaller, commercially viable fields were found elsewhere in Napo, but poor company-government relations have discouraged their development. Napo holds nearly all of Ecuador's known oil reserves—a low-sulphur, 29° to 31° API crude.

Speculation that Oriente's Pastaza Province contains vast reserves has faded. The Amazon Basin, in which Texaco-Gulf made its discoveries, extends south through Pastaza into Peru. International firms rushed to obtain concessions for virtually the entire province after the initial Texaco-Gulf discoveries. Exploratory drilling during 1971 and 1972 failed to discover oil, however, and governmental interference has caused most companies to abandon their concessions.

Further exploration and development could increase Ecuadorean oil reserves by 1 billion to 1.5 billion barrels. Although the bulk of new reserves would probably be discovered near currently producing areas, some commercial deposits might be found in more remote, eastern Napo where CEPE, the Ecuadorean State Petroleum Corporation, is currently exploring. CEPE recently struck oil at two fields, Shiripuno and Tivacuno, but transport costs make the heavy, 19° to 21° API crude noncommercial. The Argentine company, YPF, has had some success in northern Pastaza. Its first exploratory well, Curaray X-1, was tested at 1,000 b/d of 25° to 30° API crude; the company plans to drill two more exploratory wells this year.

Increased investment would also permit exploitation of Ecuador's 11 trillion cubic feet of proved and probable natural gas reserves. Preliminary work is under way on a gas recovery plant in Napo. Reserves in the Gulf of Guayaquil lie unexploited because of government disputes with the operating company, Northwest Energy.

Capabilities and Constraints

CEPE, the sole domestic petroleum company, lacks both the technical expertise and the financing needed for exploration and development. The company has drilled only five wells in its five-year existence. CEPE's inexperience is exacerbated by the difficult terrain of Ecuador's eastern jungles and by equipment shortages. Despite high international oil prices, subsidized domestic petroleum prices and depressed international sales limit CEPE's finances. CEPE is dependent on profits for the bulk of its operating income; petroleum taxes and royalties from foreign companies are earmarked for other purposes.

Some governmental entities recognize the need to attract foreign firms. Ecuador's tough nationalistic petroleum policies caused an exodus of foreign firms, culminating late last year with

Gulf's withdrawal. The resulting dearth in exploration since 1972 has affected thinking in the Hydrocarbon Directorate of the Ministry of Natural Resources, CEPE's bureaucratic rival. Exploiting widespread dissatisfaction with ineptitude and corruption in CEPE, the Hydrocarbon Directorate has pushed for new incentives for the foreigners. Texaco was pleasantly surprised at Quito's accommodating attitude during recent discussions of the 1977/78 work program.

Outlook

Development of new Ecuadorean reserves probably will do no more than offset depletion through the early 1980s. Although governmental attitudes toward foreign companies should continue to improve, Quito's past record and Ecuador's apparently limited geological potential will discourage any great influx of foreign investment.

BRAZIL

Despite spasmodic exploration since the 1930s, Brazil's oil potential remains largely unknown. Currently, the most promising areas appear to be offshore. Petrobras, the state oil company, has intensified offshore exploration since 1973, efforts that have led to important finds in the Campos Basin off the coast of Rio de Janeiro as well as a promising strike at the mouth of the Amazon. Despite these successes, Petrobras does not have the financial and technical capacity to rapidly increase exploration and production. The government is looking to foreign companies to accelerate the search for oil but so far has been reluctant to provide sufficiently attractive terms.

Geological Prospects

Most of Brazil's oil is produced in coastal fields in the northeast. The steady decline in onshore production has offset slowly expanding offshore output, causing Brazil's total oil production to stagnate since 1969 at about 175,000 b/d. Promising offshore seismic surveys and the discovery of the large Campos Basin—accounting for 90 percent of Brazil's 668-million-barrel proved and probable oil reserves—have prompted Petrobras to concentrate exploration on the 850,000-square kilometer continental shelf. The government's ambitious oil program calls for spending roughly $730 million for exploration and development this year, nearly double 1976 expenditures. An average of 168 new exploratory wells, mainly offshore, are planned annually over the next three years; only 30 wells were sunk in 1973.

Except for the deep Campos deposits, Petrobras is focusing its offshore exploration in relatively shallow waters. In 1976, Petrobras made offshore oil and gas discoveries at the mouth of the Amazon River, which geologists believe to be among Brazil's most promising areas. Gas flow rates at four test wells were prolific, ranging between 15 million and 25 million cubic feet per day. Small oil discoveries have been made near Sergipe, Alagoas, and Rio Grande do Norte in the northeast.

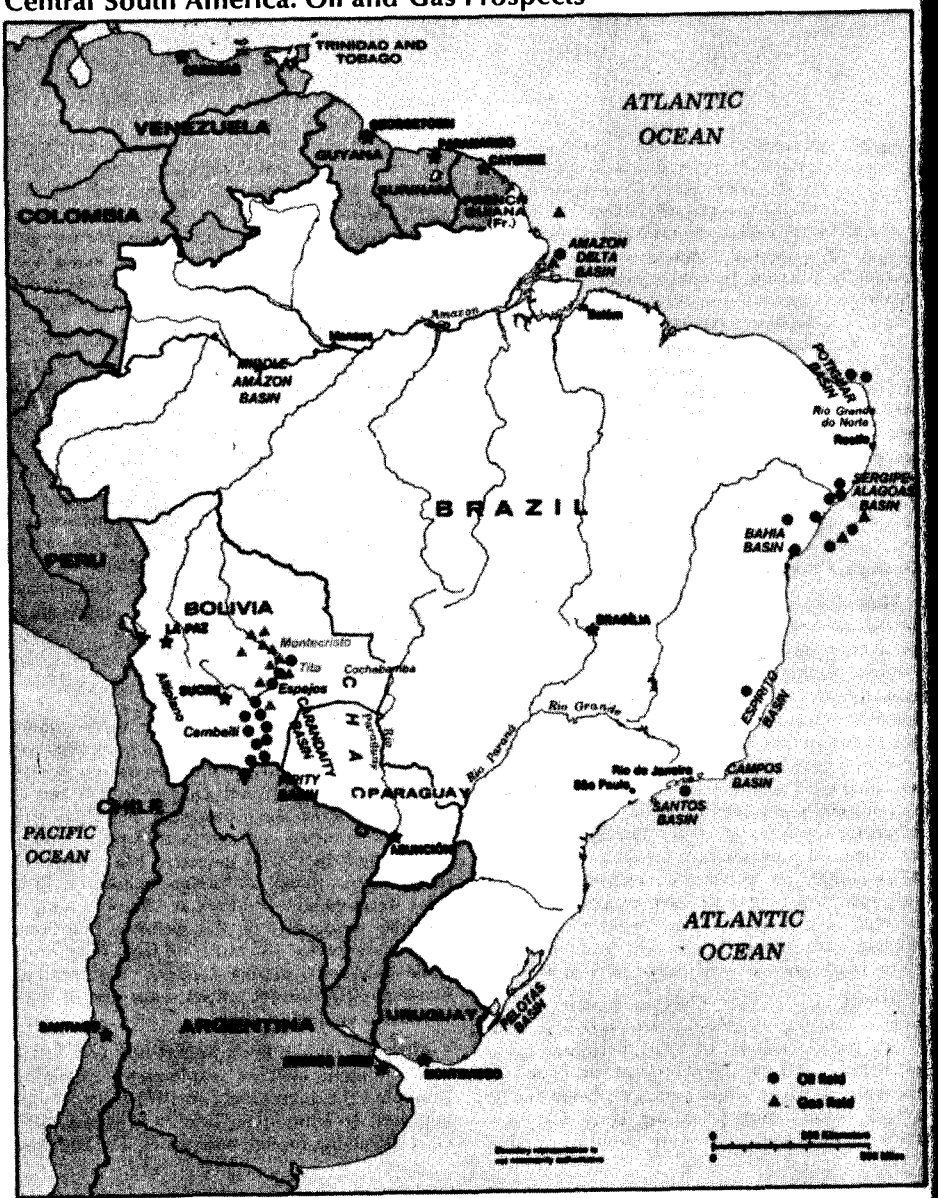
Over the past year, Petrobras concluded its initial round of risk contracts with four international oil companies—Exxon, British Petroleum, ELF/AGIP, and Shell—to undertake more difficult exploration in deep offshore formations. In mid-1977, Petrobras opened a second round of bids for risk contracts on 25 offshore blocs (compared with only 10 blocs offered in the first round) located at the mouth of the Amazon and in the Santos and Pelotas Basins in the south. Blocs were allocated based on seismic data indicating some potential although no commercial finds have been made. Contract negotiations should begin by yearend.

Capabilities and Constraints

Petrobras, although one of the world's more competent state oil companies, is among the most nationalistic and bureaucratically entrenched of Brazil's state enterprises. Despite a shortage of technical and financial resources, Petrobras officials have resisted and continue to resist foreign involvement in the oil industry. The company's unwillingness to call on foreign technical help to solve development problems at Campos exemplifies the seriousness of the problem. Petrobras lacks the expertise to extract oil from deep limestone reservoirs, among Campos' best sources. Consequently, most Campos wells are in shallower, lower quality zones.

Although mounting oil import bills and Petrobras' limited offshore exploration capability prompted the government in 1975 to invite foreign bids on lease areas, Brasilia is having difficulty attracting foreign companies. The compan-

Central South America: Oil and Gas Prospects



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companies complained that, under the first round of risk contracts, Petrobras offered only small blocs, saving the best areas for itself. Some companies also believe that Petrobras withheld vital geophysical data from the seismic package sold to them. Moreover, Brazil insisted on contract restrictions limiting company profits: (a) any gas found would belong to Brazil; (b) companies' oil profits would be limited to the rate specified in their bids; and (c) exploration must be completed in a short period of time.

Financial constraints will compel Brazil to continue dependence on foreign company participation in oil expansion efforts. Offshore development will be particularly expensive; Petrobras estimates that $4 billion will be needed to bring Campos into full production. Development along the Amazon River and off its mouth also will be costly because of the need for extensive infrastructure and sophisticated technology.

Recognizing these handicaps, President Geisel recently ordered Petrobras to stop obstructing foreign participation and to open promising geological areas to risk contracts. As a result, in the latest round of contracts Petrobras opened more areas for exploration, offered to negotiate compensation for gas production, and reduced seismic data fees. Brasilia also partially lifted restrictions on importing oil equipment similar to that produced locally. The government went ahead despite strong protests by Brazilian manufacturers, indicating the importance it attaches to rapidly developing the country's oil resources. Changes in the Petrobras leadership this year designed to make the company more effective are unlikely to have much immediate impact, however.

Outlook

Brazil's future as an oil producer rests heavily on the results of offshore exploration, which is still in an early stage. Even if some promising structures prove productive, however, it is unlikely that Brazil will be able to develop them in time to achieve its goal of becoming self-sufficient in oil by 1986. Past public statements by Brazilian officials that domestic oil production will reach 700,000 b/d by 1980 are also highly optimistic. Output from the Campos Basin probably will more than double Brazil's oil production to 400,000 b/d by the early 1980s, but these supplies still would meet only about 30 percent of Brazil's oil requirements at that time. Achieving higher levels of production will depend to a great extent on Brazilia's ability to attract foreign companies.

BOLIVIA

Bolivia is almost certain to increase its oil reserves from the present 230 million to 270 million barrels given the country's recent discoveries and numerous geological structures yet to be explored. Even without additional discoveries, oil production should double to about 70,000 b/d over the next several years as already discovered fields are developed.

Geological Prospects

Bolivia initially discovered oil in the 1920s in the south and southeastern part of the country. Not until the early 1960s, however, was large-scale exploration and development undertaken. The exploration effort helped raise reserves to their present level of 230 million to 270 million barrels, located primarily in the central and southeastern part of the country (see map, page 16). Extensive gas reserves have also been discovered, and gas is exported to Argentina. Recent major commercial finds include the 15-million-barrel Cambeiti Field in the southern zone and the 9-million-barrel Espejos Field in the central zone, both discovered by YPFB, the Bolivian state oil company. Occidental's Tita Field in Carandaity Basin in the southeast has reserves of 60 million to 100 million barrels. Exploration in the northwest, the south, and on the Altiplano has thus far been unsuccessful.

Capabilities and Constraints

In 1972 the Bolivian Government recognizing that foreign technology, manpower, and financing were indispensable for further development, broke YPFB's monoply on oil exploration. The new law grants foreign companies concessions of 1 million hectares and 40 to 50 percent of newly discovered oil, with all exploration and production costs to be paid by the companies. In mid-1977 La Paz indicated it planned to sweeten incentives for private companies to encourage both expanded exploration activity and intensified development of producing fields where output is on the decline.

After strong initial company interest, several international companies have discontinued operations in Bolivia. Of the 18 tracts assigned to foreign companies under production-sharing contracts with YPFB, 12 have been returned and another three are currently being reassessed. Only Occidental, Tesoro, and Phillips are still active and, while the latter continues to drill in the Cochabamba area, it has yet to report any strikes. Despite the country's attractive investment laws, exploration failures in many of the tracts assigned to foreign firms have dampened company interest.

Outlook

Although some oil remains to be found in Bolivia, reserves are not expected to rise enough to make the country a major producer. Waning foreign company interest, despite a liberal investment climate, is restraining exploration. Production, however, should increase to 70,000 b/d by mid-1980, as already discovered fields are developed.

COLOMBIA

Bogota is finally taking policy moves to reverse the steady decline in proved oil reserves and production. Limited geological potential, however, makes the chances of a major reversal slight. Given the expected level of exploration over the next five years, new finds are unlikely to permit significant increases in reserves from the current 525 million barrels. In these circumstances the best Colombia can hope for is to maintain crude output at the present level of 146,000 b/d.

Geological Prospects

The bulk of Colombia's proved reserves are located in the Middle Magdalena Basin, which has been under extensive exploitation since the 1920s (see map, page 8). About one-fourth of current production comes from Putumayo Fields discovered by a Texaco-Gulf consortium in the mid-1960s—Colombia's only recent important field. Exploration centers on the Magdalena Basin, the Putumayo Basin, and areas west of the Guajira Peninsula, where sizable (3 trillion cubic feet) gas reserves exist. Colombia also lays claim to potentially rich offshore deposits in the Gulf of Venezuela, but exploration awaits settlement of its ownership dispute with Venezuela.

Aside from the Gulf of Venezuela area, Colombia's geological potential is only poor to fair. Recent exploration, however, has uncovered sizable natural gas deposits along the Guajira Peninsula where proved gas reserves could support production of 400 million cubic feet per day (70,000 b/d crude equivalent). Further evaluation of the Guajira gasfields could lead to a doubling of known resources. Bogota also plans to develop gas deposits in southeastern Colombia and along the north coast. Total proved gas reserves amount to 5 trillion cubic feet, up from 2.8 trillion cubic feet in 1971. Proved oil reserves, by comparison, have declined by 850 million barrels since 1971

Capabilities and Constraints

Colombia's government-owned oil company—Ecopetrol—lacks the financial resources or technical expertise to undertake serious exploration and development of the country's limited oil and gas potential. Until recently, however, government policies tended to discourage foreign interest in exploration and development by keeping a tight lid on domestic fuel prices. As a result, the number of wildcat wells drilled since 1970 has averaged only 18 per year. Most of these were carried out under the auspices of Ecopetrol.

Beginning in 1977 Bogota moved to adjust domestic pricing policies in an effort to slow the decline in proved oil reserves. Prices on production from new discoveries have been raised to the international level and use of production-sharing contracts has been introduced. Contract terms, however, do not appear liberal enough to attract a great deal of foreign company interest given the high costs and difficulty of exploring Colombia's rugged terrain. Under contract terms, foreign firms receive 40 percent of any production from new fields and are reimbursed for 50 percent of drilling expense in the event commercially exploitable fields are located.

Outlook

Although exploration is increasing as a result of changes in government policy, a substantially greater effort will be required to halt the decline in proved reserves and production. Given the limited geological potential for oil, the exploration effort will probably consist of drilling some 20 to 30 wildcat wells annually, up from the average during the period 1970-76 but still well below the rate of 80 per year the government has been planning.

CHILE

Chile is unlikely to find significant petroleum and gas reserves in the next decade. Exploration in the Straits of Magellan is unlikely to do more than double the current reserves of 180 million barrels of oil and 2.5 trillion cubic feet of natural gas. Extensive exploration in large unexplored areas will not be forthcoming in the near future, given Santiago's reluctance to provide foreign oil companies a freer operating hand.

Geological Prospects

Concerted exploration between 1945 and 1964 discovered Chile's currently producing fields in an area bordering the Straits of Magellan (see map, page 6). Continuing efforts in the area since 1964 have failed to uncover additional significant deposits; as a result reserves have dropped to about 180 million barrels while production has dropped to 26,000 b/d. Limited drilling elsewhere also have proved unsuccessful. Most recently six dry holes were drilled in shallow coastal waters off Valdivia.

The Straits themselves probably contain an additional 200 million barrels of oil and 1.5 trillion to 2 trillion cubic feet of gas. Habitually stormy weather prevented exploration until September 1976 when ENAP, the state petroleum company, leased a US-owned, all-weather drilling platform. ENAP has drilled 15 to 20 wildcats since September with encouraging results. The existence of new petroleum reserves outside this area is less likely, but seismic studies are under way along Chile's continental shelf particularly in regions south of Valparaiso.

Capabilities and Constraints

While ENAP is a competent company, it lacks both the advanced technology to exploit the Straits fully and the financing and manpower necessary for extensive exploration of the continental shelf. Realizing this, ENAP has signed a contract with Santa Fe Corporation to purchase additional offshore drilling platforms for delivery in 1979. In another move to beef up oil sector activity, Santiago ended its 50-year exclusion of foreign companies from petroleum exploration and production. Terms of Chilean service contracts, however, are too rigid to stimulate foreign interest. International firms, for example, continue to be excluded from activity in the relatively promising Straits area. The continuing drop in crude production is spurring Santiago to modify the financial aspects of service contracts proposals, but so far only one company—Arco—appears interested.

Outlook

We expect little decline in Chile's demand for imported petroleum for at least five years. While gas reserves remain virtually untapped, progress on a proposed liquefied natural gas (LNG) plant has been stalled for some time and completion before the early 1980s is unlikely. Production from new crude reserves in the Straits of Magellan is unlikely to do more than double current output to 50,000 b/d by 1990.

GUATEMALA AND BELIZE

After 25 years of unsuccessful exploration, Guatemala discovered commercial petroleum deposits near its Mexican border in 1973. Although the size of the deposits is uncertain, preliminary analysis indicates reserves of at least 27 million barrels—extremely small by world standards but the largest in Central America. Development has proceeded slowly because of the remoteness of the deposits and the unattractiveness of Guatemalan petroleum policies. Despite increased exploration activity in the wake of the Guatemalan discoveries and positive seismic surveys, Belize has not yet discovered commercial petroleum deposits.

Geological Prospects

The recent Guatemalan discovery—termed the Rubelsanto Field—is located in the Peten area (see map, page 2). The deposits lie in the Cretaceous Coban zone, adjacent to and similar in geological structure to the rich Reforma Fields in southeast Mexico. Detailed geological and seismic tests have defined some 37 structures, of which 10 could be significant. The oil found thus far has been in the 23° to 32° API range and its sulfur content is high, about 3 to 4 percent. Despite the moderate depth—2,300 meters—and the open structure of the formation, drilling has been expensive and difficult because of the presence of large quantities of hydrogen sulfide and sulfur dioxide.

The consortium of Basic Resources International and Shenandoah Oil has completed at least four producing wells in the Rubelsanto Field with test flows ranging from 1,000 to 3,000 b/d. Total production from the field has been restricted to about 3,000 b/d, however, because of transport difficulties. A 190-kilometer, 12-inch pipeline from the Rubelsanto Field to the refinery and port at Puerto Barrios is scheduled to be constructed by mid-1978. The $33 million pipeline, which is being built by the French construction firm of Entrepose SA, should allow output to reach 15,000 b/d.

Guatemala also is exploring offshore in the Gulf of Honduras. Centram-Zamora, the only other oil company currently active in Guatemala, drilled to 1,800 meters with disappointing results. A second well reportedly has been drilled to between 3,050 and 3,350 meters in an effort to reach the Todos los Santos geologic formation; no results have been reported.

Spurred by Guatemala's discoveries in recent years, Belize shifted its search for oil from the northern part of the country to the south. In August 1976, Exxon purchased the majority share in nine exploration leases, mostly offshore in southern Belize, and agreed to carry out extensive exploration by mid-1977. Exxon subsequently drilled an exploratory well to 4,000 meters in the Gulf of Honduras but apparently did not find oil. In mid-1977, Exxon began drilling another offshore exploratory well, planned to reach 3,660 meters.

Capabilities and Constraints

Early in 1976 Guatemala passed a petroleum law allowing service-contract arrangements with foreign oil companies. The arrangements call for a 51-49 production-revenue split in favor of the government, and require a $1 million signature bonus for each concession. The government may take its share of production in kind or cash; in either case the government's share will include credit for the operator's tax liability. The country was divided into 28 prospecting zones of 200,000 hectares each with 5-year exploration and 20-year production terms.

Guatemala's new law does not provide enough incentive to attract large foreign oil companies

whose capital, experience, and technology is crucial to the success of the country's oil program. Several companies have withdrawn applications for exploratory rights because of the law and the complexities of negotiating with the government. This leaves Guatemala with only two companies operating in the country, one of which—Centram Zamora—apparently has only a limited commitment to large-scale exploration.

Because of the improved prospects for finding petroleum in the wake of the Guatemalan discoveries, Belize is moving cautiously. The government is reviewing its oil laws to secure a larger share of new discoveries and is considering establishing a research unit to advise on oil matters. Because it lacks the necessary expertise and financial resources, Belize must depend on foreign oil companies to carry out its exploration program. Company enthusiasm has been dampened, however, by the fact that important potential deposits lie in a contested area in southern Belize claimed both by Belize and Guatemala.

Outlook

Guatemala has recently become Central America's first oil-producing country. Discoveries in the Rubelsanto Field and completion of the pipeline could allow production of up to 15,000 b/d in 1978. Despite promising geological prospects, the pace of further exploration and development depends on the government's ability to encourage foreign participation. In the case of Belize, the border dispute with Guatemala and the lack of success thus far will continue to inhibit exploration. If the border dispute can be resolved, Belize has a better than even chance of finding commercially exploitable deposits, given existing knowledge of geological formations. The amounts involved, however, would probably be small.

PARAGUAY AND URUGUAY

Paraguay

Paraguay has thus far discovered no commercial oil deposits despite years of looking. The exploration effort has been concentrated in the Chaco area west of the Paraguay River, where favorable geological formations have been identified. Of the five sedimentary basins in this region with oil potential, two—the Carandaity and the Pirity—stretch into Bolivia and Argentina where they are already being exploited (see map, page 16). Exploration in the Gran Chaco began primarily in the Carandaity Basin in the 1940s and has continued on an intermittent basis to the present without success.

Paraguay is actively encouraging oil exploration by foreign companies. Its oil legislation is generous as is its treatment of foreign capital. Although infrastructure is largely undeveloped, its absence would not be an impediment to development given the relatively hospitable terrain. The liberal investment climate, the general absence of physical constraints, and the location of oil in Bolivia and Argentina have helped sustain company interest in Paraguay. Three groups—Texaco Paraguay, Chaco Exploration, and Esso-Aminoil—are scheduled to drill five or six wells this year.

Uruguay

Uruguay has no oil production and poor geological prospects for developing a reserve base. Although offshore seismic surveys in 1972 indicated the likelihood of commercial deposits in the Salado Basin (at the mouth of the River Plate, between Argentina and Uruguay), two wells drilled there last year by Chevron proved dry (see map, page 6). Exploration depends on the willingness of foreign companies to drill under contract, since the government company lacks both funds and technology. Lack of interest on the part of major oil companies has left Uruguay largely dependent on Latin American firms to carry out its small-scale onshore program, which requires less sophisticated technology than offshore drilling.

South and East Asia

The most favorable prospects for increased Asian oil production center on the continental shelf off India, onshore and offshore areas in Burma, and the numerous structures from which Indonesia, Malaysia, and Brunei currently produce crude oil. Geological work completed so far suggests that natural gas, rather than oil, will continue to dominate the hydrocarbon-energy developments in Pakistan, Bangladesh, and Thailand. Exploration of the long eastern continental shelf from South Korea to Vietnam has barely begun, and prospects for both oil and gas are uncertain. Most governments in the area are reasonably hospitable to foreign oil companies; the principal deterrents to exploration are high costs and numerous territorial disputes.

INDONESIA

Indonesia, with 14 billion barrels of proved and probable reserves, should be able to increase oil production at least through the mid-1980s. Declining production from older Sumatran fields is being stabilized and output may even increase for a few years. Output from offshore fields, where geological prospects for further development are promising, should continue to increase. Despite a recent falloff in exploration of the newer offshore areas, developmental drilling has been maintained and little basic growth momentum has been lost. The government has altered some of the harsh contract terms imposed on foreign companies a year ago, giving impetus to a revival in exploration.

Geological Prospects

Indonesia has been an oil-producing country since the 1890s, but it was not until in 1967 that foreign oil companies began intensive exploration. Pertamina, the state oil institution, is responsible for all aspects of oil development, refining, and marketing. Foreign companies are limited to upstream operations—exploration and production of crude oil or gas—as contractors to Pertamina, receiving prescribed shares of their output to recover investment and profit margins. More than 30 companies actively work some 50 leased areas both onshore and offshore.

Indonesia's oilfields are scattered throughout the islands, with principal producing locations in Sumatra, Java, East Kalimantan, and West Irian. Although more than half of current production still comes from older onshore Fields, future increases are expected to come from newer offshore discoveries. The Duri and Minas Fields in central Sumatra are by far the largest oil deposits yet discovered. Under development by Caltex since the early 1940s, these and nearby fields accounted for 56 percent of Indonesian crude production last year (1.5 million b/d). Caltex's producing areas are characterized by high geothermal gradients with numerous slate-capped sandstone reservoirs overlying a granite basement rock that precludes the possibility of deeper producing zones.

. Despite reservoir pressure problems in its two main fields, Caltex's production will not fall off precipitously very soon. Authoritative assessments place proved and probable reserves in the range of 6 billion to 8 billion barrels. The company's active exploration program in adjoining Sumatran areas continues to uncover relatively small oil deposits—some 20 new discoveries in 1975 and 1976—most of which are not yet hooked up to existing gathering facilities. Developmental drilling by Caltex accounts for roughly one-third of the annual total in Indonesia. Given the secondary and tertiary recovery efforts in progress, Caltex's production may be expected to increase moderately in the near term before starting a slow and steady decline sometime in the 1980s.

On Sumatra, Pertamina and Stanvac work many small deposits that are beginning to play out. Although development and additional exploration continue, there are few signs that this trend will be turned around. Pertamina's operations on Java and East Kalimantan offer better prospects for expansion but so far appear to suffer from a lack of aggressive management or risk-taking. A third company, Tesoro, operates under a special contract with Pertamina, developing and producing from the two oldest fields in Indonesia. Tesoro still manages to eke out some 13,000 b/d from the Sanga-Sanga and Tarakan Fields even though they have been producing for 84 and 71 years, respectively.

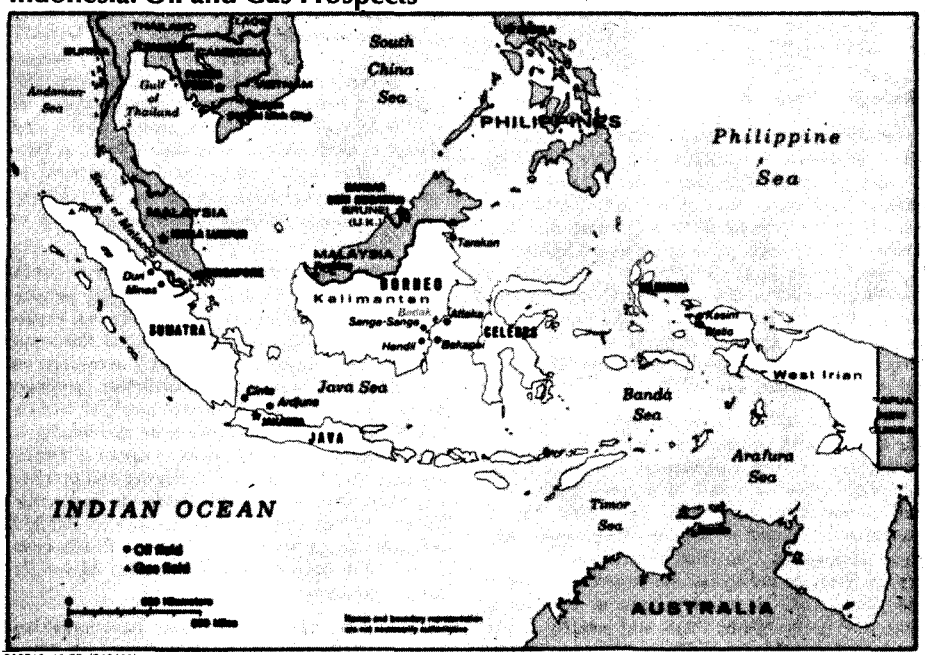
Production-sharing contractors have provided the growth segment of the Indonesian oil indus-

try, starting with the purchase and awarding of lease areas in 1967. For the most part their leases are in offshore or isolated jungle areas that Pertamina has shied away from for technological and financial reasons. Crude output by contractors trickled in 1971 at the rate of 12,000 b/d, jumped to 210,000 b/d in 1973 when Caltex's production peaked, and last year rose to 540,000 b/d. Virtually all future expansion in Indonesian output is slated to come from the production-sharing contractors.

Promising finds to date have occurred off the north coast of Java (Arco's Ardjuna Field and Natomas' Cinta Field), on and off the coast of eastern Kalimantan (Union-Japex's Attaka Field, TOTAL Indonesie's Handil and Bekapai Fields), and Irian Jaya (Petromer Trend's Walio and Kasim Fields). Producing zones in these Miocene structures tend to be deeper than in the older producing fields, ranging from 1,520 to 3,050 meters. Offshore drilling typically is in water depths of 45 to 90 meters. In addition to oil, natural gas discoveries are the largest yet found in Southeast Asia.

Continued heavy investment in drilling is essential because of the typically small size of Indonesian deposits; those discovered in recent years generally range from 50 million to about 200 million barrels. Nevertheless, discovery rates are impressive. In the past four years the discov-

Indonesia: Oil and Gas Prospects



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ery ratio for exploratory oil drilling has averaged 22 percent; if both oil and gas are included the average rises to 31 percent. Developmental drilling for oil has produced a success ratio close to 80 percent. The overall drilling program during these four years has put on stream a net average of more than 200 new producing wells each year. In view of this record and considering that less than 20 percent of prospective oil-bearing structures in the country have been explored, continued growth in oil production seems certain as long as adequate investment levels are sustained.

Capabilities and Constraints

Indonesian petroleum development would flounder without heavy foreign involvement. Although Pertamina's operations cover the gamut of oil activities, its weakest sector is exploration and development. "Indonesianization" of foreign oil operations exists only for routine work such as low-level manning of drilling rigs or overseeing storage facilities. Government hopes for a dominant Pertamina role in increasing oil resources have long since vanished. Indeed, Pertamina recently opened up several of its own prospective oil territories to participation by foreign companies in joint-ventures.

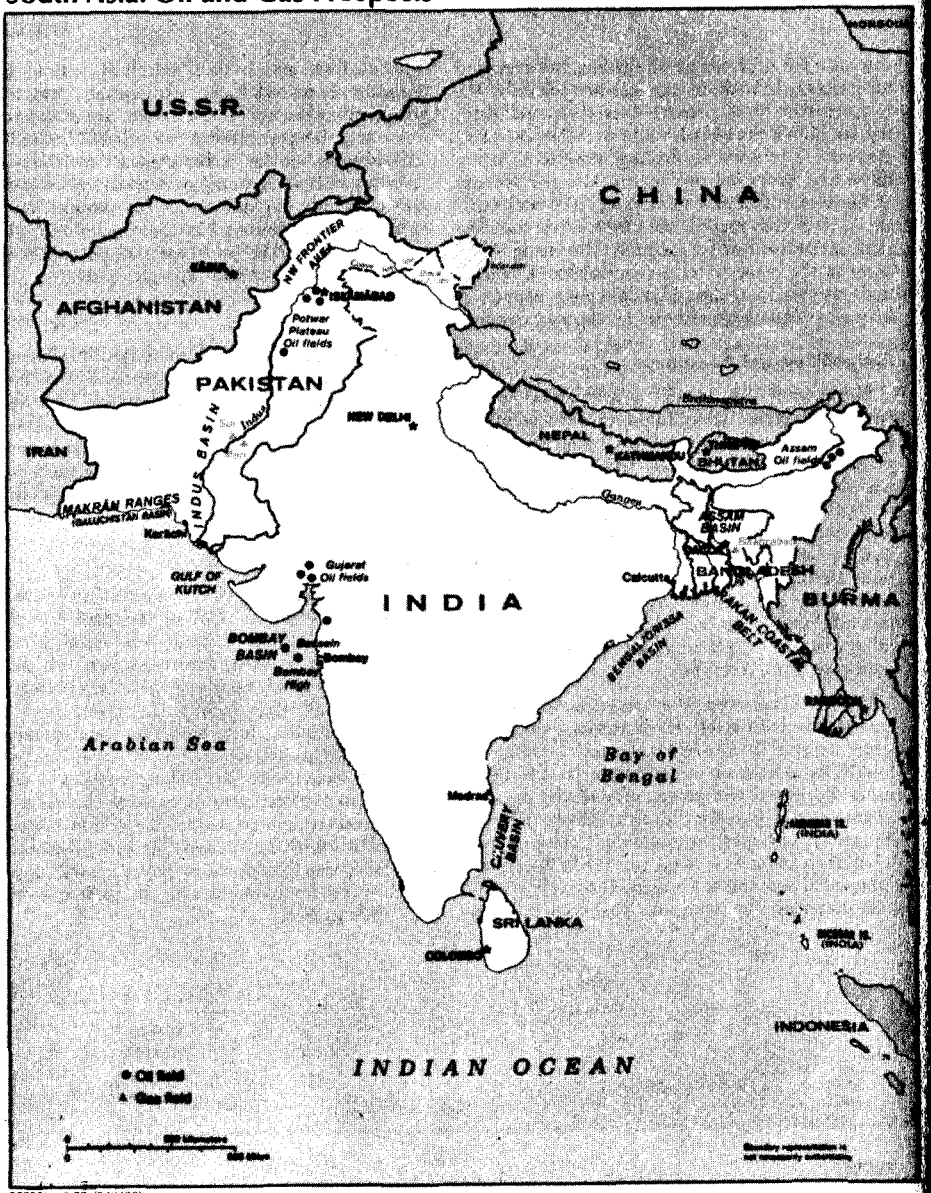
Relations between the government and oil companies were relatively harmonious until last year. The 1975 Pertamina financial crisis, followed by wholesale replacement of the Pertamina old guard and ascendancy of the so-called "technocrats" to higher levels in the government hierarchy, changed the situation. Under the new leadership the government in mid-1976 imposed substantial revision of foreign oil company profit and cost-recovery margins. The companies regarded these actions as a breach of contract and rapidly curtailed their exploration programs. Amid prophecies of doom for Indonesia's oil industry, the government in early 1977 admitted it had gone too far in the contract revisions and began to offer the companies a variety of incentives to spur exploration. A few companies already have announced further exploration plans as a result of the new terms, and others are expected to follow suit later this year.

Outlook

Prospects for continued increases in Indonesian crude production are good. Favorable geology, high success ratios in exploration, and huge areas remaining to be explored need only be complemented by investment. Expedient government policy will see to that. Technological short-comings and financial needs will dictate government accommodation of foreign companies' interests to the extent necessary to sustain growth in oil output.

The companies will be more cautious in expanding operations than in the past, but they should continue to put up substantial venture capital if prospective returns appear adequate. Caltex's secondary recovery operations promise at least to halt the decline in output from its Sumatran fields. Judging from the correlation between exploration in recent years and the annual increase in producing wells, a modest upturn in exploration activity should be sufficient to guarantee annual crude production increases of about 100,000 b/d. On this basis, Indonesian crude output could reach more than 2 million b/d by 1985, compared with the current level of 1.7 million b/d.

South Asia: Oil and Gas Prospects



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INDIA

India has good prospects for oil development and is making significant progress in exploiting its oil potential. Production will double by 1983, and chances are good that current exploration efforts will result in discoveries that will expand the present base of 2.3 billion barrels of proved and probable reserves. Over the next five years New Delhi plans to spend nearly $1 billion on its major new oil find—the Bombay High - Bassein offshore area. In addition, the government is backing a program for increased offshore oil and gas prospecting by foreign oil companies under contract. Despite this favorable outlook, with consumption increasing at a minimum of 5 to 6 percent per annum, imports are expected to remain close to current levels of 300,000 b/d through the early 1980s.

Geological Prospects

The Indian effort to expand oil production has centered in the Arabian Sea west of Bombay. Although this area's potential was first identified by surveys in 1966, no exploration took place for eight years as the finds were not deemed commercial at pre-1973 prices. Since 1974, when the first well was completed, development has been rapid.

Current Bombay High production of 32,000 b/d is expected to reach 80,000 b/d late this year. The next phase of development will involve the laying of two parallel pipelines for gas and crude to onshore terminals near Bombay, a distance of 215 kilometers. Four platforms and 16 production wells, onshore terminal facilities, and a gas fractionation plant will also be built. By the early 1980s a production rate of 200,000 b/d of oil and 105 million to 140 million cubic feet of gas per day is envisaged.

In 1976, two more major fields were discovered at Bassein, about 60 kilometers east of the Bombay High and virtually on the direct pipeline route to Bombay. Production from the Bassein Field is not likely to begin before 1979. Outside the Bombay High - Bassein Fields, three other offshore areas are being explored under production-sharing contracts. Two American firms (Reading & Bates and Natomas) have each drilled two dry holes in concessions located in the Gulf of Kutch and the Bengal/Orissa Basin. Canadian-owned Asamera Oil Company is currently drilling in the Cauvery Basin.

New Delhi appears dissatisfied with progress in offshore areas other than the Bombay High - Bassein and Cauvery tracts. Reading & Bates and Natomas have left the Kutch and Orissa areas. New Delhi is considering contracting other foreign companies to develop their concessions, with India retaining ownership of the fields and the oil produced. The Janata government, however, is not actively pursuing this policy, which appeared imminent under the Gandhi regime.

India has six main producing onshore fields; the two most important are Ankleshwar in Gujarat and Nahorkatiya in Assam. The latter is operated by Oil India Limited (OIL), an enterprise owned jointly by the government and Burmah Oil Company. The Gujarat fields are operated by the Oil and Natural Gas Commission (ONGC), the state-run enterprise that dominates exploration in India. New Delhi has nationalized nearly all of its downstream oil industry and a takeover of OIL is anticipated.

Indian onshore development plans call for deep drilling at previous sites where drilling was unsuccessful or where oil was found in then-uneconomic quantities. An extensive secondary recovery program is also planned. If New Delhi follows through on these plans, foreign technology will probably be required. As production is now declining in most of these older fields, the effort

may have little net impact on total onshore production. India's proved and probable reserves of 2.3 billion barrels—of which 1.4 billion are offshore—are likely to increase with further exploration.

Capabilities and Constraints

Although Indian oil policy historically has stressed self-reliance, some erosion of this attitude has occurred since the oil-price hikes of 1973 and 1974. New Delhi is now willing to enter into production-sharing contracts with foreign oil companies and to use foreign consultants in offshore development. Nevertheless, the government continues to rely primarily on ONGC; a major move to spur activity through domestic or foreign private oil firms is unlikely even if the cost is a slower pace of developing oil reserves.

Financing development of the Bombay High area does not appear to be a serious problem. The cost of the program through 1983 is estimated at $1 billion. The World Bank will provide $150 million, foreign commercial banks $50 million, bilateral aid $50 million to $100 million, and $170 million is expected to be available from ONGC and OIL internal sources. The balance will come from the government. With finances and technological expertise concentrated on the Bombay High, other development efforts both onshore and offshore are likely to be constrained until the early 1980s.

Outlook

India is on the verge of substantially increasing oil production. Given developments now in train, output should double over the next six years, reaching the 460,000 b/d planned by New Delhi. Even with this expected increase in production, we estimate that imports, currently about 300,000 b/d, will remain at about the same level given expected growth in domestic consumption. The potential for even greater additions to oil and gas reserves appears high in view of the extensive exploration efforts currently under way. Development of this added potential, however, is not expected before the late 1980s, due to India's preoccupation with the Bombay High and to the time lag between finding new oil reserves and commercial production. The recent replacement of the Gandhi government by that of the Janata Party is unlikely to lead to major changes in Indian attitudes toward foreign oil company operations.

MALAYSIA

Malaysia has the potential to become one of the area's larger oil and gas exporters. The growth of production, however, has not been as fast as had been expected. Exploration and development programs by the major oil companies were sharply curtailed in 1975 and 1976, largely as a result of ambiguous government policies enacted in 1974 and 1975. Although policies are now being clarified, we expect foreign oil companies to move cautiously before investing heavily in Malaysia.

Geological Prospects

With the exception of the long developed and now depleted onshore Miri Field in Sarawak, exploration activities and major discoveries have been limited to offshore areas. The extensive continental shelves off peninsular Malaysia and north of Sarawak and Sabah in Borneo encompass a significant number of sedimentary basins containing numerous small oil-bearing structures. The area offshore from Sarawak, adjacent to major fields off Brunei, was extensively explored by Shell in the late 1960s; by 1972 five fields were producing 90,000 b/d (from depths of 2,140 to 3,330 meters). These fields accounted for all of the country's oil production through 1975.

Exploration picked up sharply in the period 1972-74 in other concession areas, principally off the west coast of the peninsula and the northwest coast of Sabah. Commercially exploitable discoveries were made by Shell and Exxon in their areas off Sabah and by Conoco and Exxon in waters 160 kilometers off western Malaysia, where wells tested at 2,500 to 6,000 b/d at depths of about 2,740 meters. Fields discovered off Sabah were Shell's Semarang, now producing some 65,000 b/d, and West Erb and South Furious, both with productive capacities of 20,000 to 25,000 b/d. Since 1975 several of these companies have relinquished their concession areas in the Straits of Malacca. The newly opened fields in Sabah increased Malaysia's production during 1976 to 155,000 b/d, and production this year is expected to be about 180,000.*

Broadened exploration has boosted proved and probable oil reserves to an estimated 2.5 billion barrels which, with proper exploitation, could support a production level of about 500,000 b/d. There have been no discoveries since 1975, but renewed exploration activity in conjunction with field development is likely to result in the proving up of additional reserves. Completion of development programs currently under way is expected to push production to about 225,000 b/d by the end of next year.

Natural gas has also been discovered in significant quantities. Shell's Luconia Field off the coast of central Sarawak is slated to supply LNG plant with a capacity of 6 million tons per year, to be located at Bin Tulu. Other commercial gasfields were discovered in the Conoco and Exxon leases off western Malaysia, but as yet there are no plans for exploitation. Malaysia's gas reserves are believed to be on the order of 15 trillion cubic feet, second only to Indonesia in Southeast Asia.

Capabilities and Constraints

Government attempts to exert greater control over oil resources led in 1974 to the creation of a national oil company, Petronas, with a charter to coordinate exploitation of oil and gas reserves and to establish new production-sharing contracts with foreign oil companies. Still small and with exceedingly limited technical expertise, Petronas' primary function to date has been to negotiate

* Malaysia became a net oil exporter in 1976. About 80 percent of production is exported and domestic requirements are met from heavier crude oil imported from the Middle East.

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new long-term contracts with the foreign companies. Although Petronas has moved into direct marketing of its pro rata share of crude oil production, it does not envision undertaking exploration and development. Rather, it will stick to monitoring foreign oil company upstream activities and gradually purchase equity shares in downstream oil and gas operations.

Investor uncertainties increased sharply in early 1975 when the Malaysian legislature enacted hastily drawn legislation giving the government almost complete control of downstream activities. The new legislation led the foreign oil companies to cease exploration and to suspend most development programs. Moreover, the negotiations for production-sharing agreements with Shell and Exxon, drawn out for more than a year, were not finally concluded until last year. Conoco, now negotiating with Petronas, is so far the only other foreign firm seeking production rights.

Although the air of uncertainty has cleared somewhat, several factors suggest that Malaysia is satisfied with a relatively slow rate of oil development.

- The country has no great need to develop oil exports as a source of foreign exchange earnings. The Third Malaysia Plan (1976-80), while largely dependent on private investment, does not envisage oil output growth above current levels. Other primary commodity exports have enabled Malaysia to maintain a healthy international payments position.
- Conservationists in the government and in the public are making strong arguments that oil resources will be depleted in the next decade unless production levels are kept low.
- Basic distrust of the government by foreign oil companies and past legislation coupled with the ill will bred by lengthy contract renegotiations are inhibiting investment decision.
- Smaller oil companies are disenchanted with the precedent-setting Exxon and Shell production-sharing agreements. The high risk and cost of Malaysian oil development projects are believed to give a clear advantage to the large companies.

Outlook

Development of Malaysia's oil resources is expected to continue at a gradual pace over the next few years. Generally favorable geological conditions and vast unexplored areas should attract sufficient foreign capital and technology. The government remains committed to preserving a strong role for the private sector in the oil business, and new legislation restricting foreign oil company operations, such as that of 1975, is not expected to recur in the near future. In these circumstances we would expect Malaysian oil production to increase to perhaps 250,000 to 300,000 b/d by 1980 or 1981.

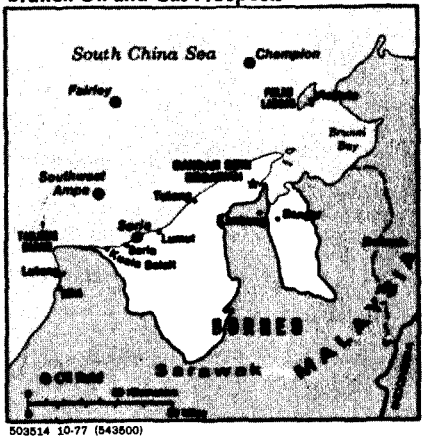
BRUNEI

The tiny British-protected sultanate of Brunei possesses proved reserves of about 2 billion barrels of oil and 11 trillion cubic feet of natural gas. Many of these deposits have been under development since the late 1920s. Discovery of offshore oil deposits in the 1960s led to an expansion of oil production to 200,000 b/d by 1972, and output since then has remained at about that level. Recent emphasis has been on extension and development of existing fields, although the possibility of additional offshore discoveries remains good.

Geological Prospects

Brunei sits astride a number of sedimentary basins containing oil-bearing structures. The Seria Field, first developed onshore by Royal Dutch Shell, has been producing steadily since 1928. Extended offshore, this field is now slated for a secondary recovery program (water injection) that will lengthen the field's life by some 30 to 40 years at current production levels. More recent discoveries have occurred offshore, again by Shell.

Brunei: Oil and Gas Prospects



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In the last two years the pace of exploration has lessened. Of 82 wells drilled by Shell in 1975 and 1976, only 21 were for exploration. Six offshore rigs are currently engaged in step-out development and appraisal drilling activities. The most recent discovery was Shell's "Osprey" Field in 1976; the commercial value of this find has not yet been established. Sun and Ashland are the only other foreign companies with concession rights in Brunei. Their limited drilling efforts have not been successful.

On the basis of field development to date Brunei's proved reserves are estimated to be about 2 billion barrels. As new offshore and onshore exploration is undertaken, reserves are likely to increase somewhat, though additional finds will probably not be large by world standards. Natural gas reserves are estimated to be about 8 trillion to 10 trillion cubic feet. Gas from the Southwest Ampa Field is currently supplying the LNG plant at Lumut at the rate of 700 million cubic feet per day.

Capabilities and Constraints

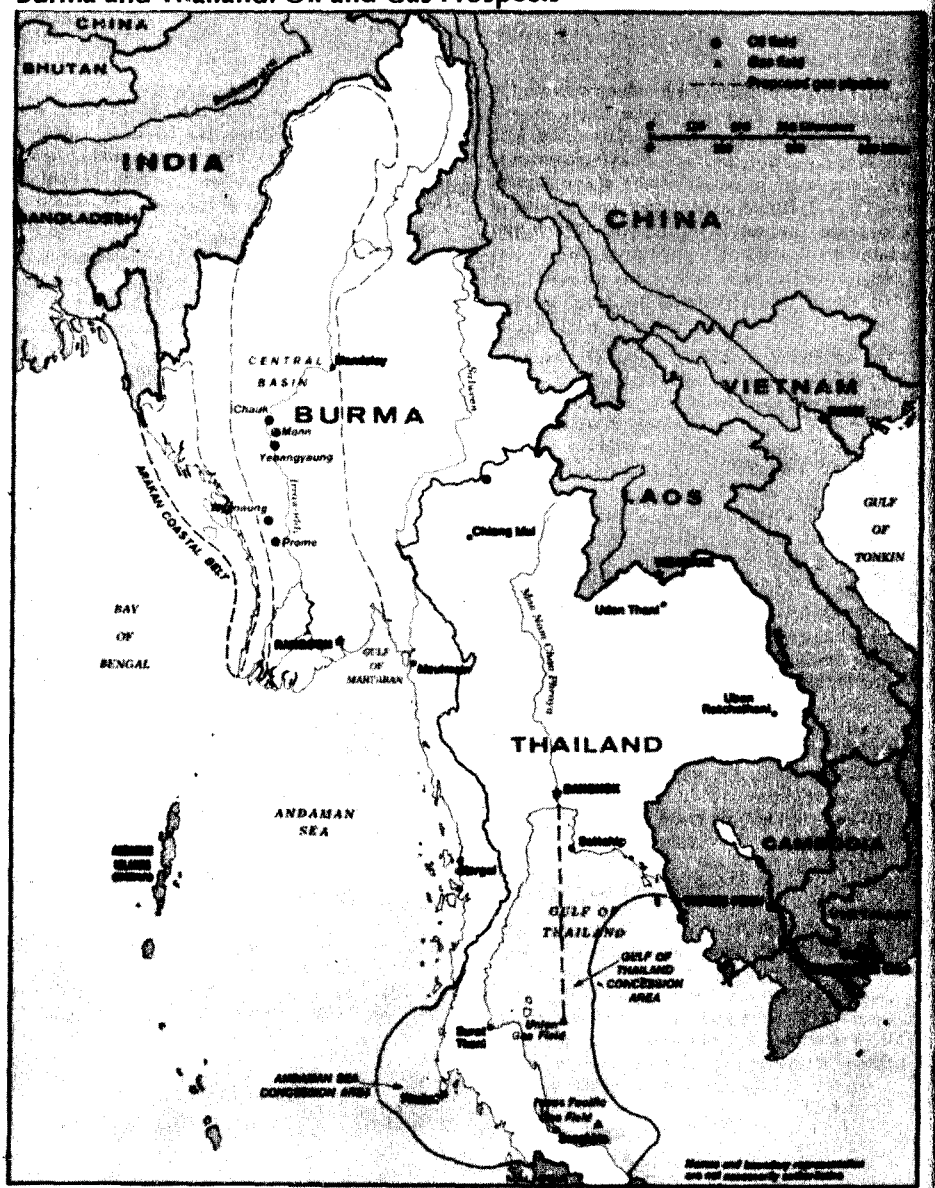
With no national oil company, Brunei has long enjoyed a comfortable and profitable relationship with its major economic benefactor, Brunei Shell Petroleum (BSP). Oil royalties, company income tax, and returns on government equity provide 90 percent of Brunei's total revenues, which in 1976 amounted to roughly $4,000 per person. In recent years the government has increased its equity in BSP to 50 percent and maintains a 10-percent share in the LNG operation. With more abundant

financial resources than can be absorbed into the economy, Brunei does not appear likely to seek radical changes in the existing relationship with Shell. Nor does the government have incentive to push for a boost in output much above present levels. In fact, Brunei exists today only because of oil; measures that would disrupt foreign company operations are extremely unlikely.

Outlook

Proven existence of sizable oil deposits will provide some incentive for Shell to continue exploration, but more with the intention of maintaining rather than increasing output. As existing fields are more fully developed, production is expected to increase modestly—to about 250,000 b/d by 1980 or so.

Burma and Thailand: Oil and Gas Prospects



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BURMA

Burma has produced small amounts of oil for many years, and geological prospects do not point to any change in this status. Offshore prospects are unclear because foreign oil operators have only recently begun exploration. The Burmese Government will probably continue to reject foreign oil company involvement in onshore development; it is likely, however, to allow a gradual increase in foreign company activity in offshore exploration.

Geological Prospects

Oil has been produced commercially onshore since the 1880s from fields in the southern half of the Central Basin. Five producing fields—Chauk, Mann, Yenangyaung, Myanaung, and Prome—account for all Burma's oil output—29,000 b/d—and almost all proved reserves, estimated at 70 million barrels. Surveys of other promising oil areas such as the Arakan Coastal Belt on the western coast of Burma are incomplete. Nevertheless, the Burmese Government and some foreign oil operators believe sizable oil and gas deposits exist offshore.

In 1974 the government granted offshore contracts to Esso Exploration (Burma), Martaban Cities Service, TOTAL, a European consortium consisting of CFP (France), Deminex (West Germany) and AGIP (Italy), and the Arakan Oil Development Corporation (AODC), a consortium of Japanese firms. All four contracts will expire this year. Under these arrangements, Exxon drilled eight holes in the Gulf of Martaban, while the other companies concentrated on the Arakan Coastal Belt. No oil was discovered in any of the areas drilled although some gas in potentially commercial quantities was found. Because of the meager results to date, Exxon, Citgo, and TOTAL have shut down operations and left the country.

Capabilities and Constraints

The state-owned Myanma Oil Company (MOC) is responsible for all Burmese petroleum exploration and production and is the government's agent for handling exploration contracts with foreign oil operators. Onshore exploration and development activity is conducted exclusively by MOC, which has used loans from West Germany, the UK, and a consortium headed by Chase Manhattan Bank to purchase oil drilling equipment and pipeline construction machinery. MOC has no offshore exploration capability and in 1974 the Burmese Government, in a rare departure from its policy of keeping the outside world at arm's length, granted Indonesian-type production-sharing contracts to four foreign operators for offshore exploration.

Since 1962 the Ne Win government has been profoundly suspicious of all foreign influence in Burma, preoccupied with tribal and Communist insurgencies in eastern Burma, and committed to socialist policies that have stifled economic growth. The main departure from policies of isolation has been in the oil business where foreign loans have equipped MOC's onshore exploration effort and foreign oil operators have been allowed to handle offshore exploration activities. Foreign oil operators, however, are prohibited from participating in the development of onshore fields.

Another potential constraint on foreign oil operations in Burma is the recent shift of MOC from the jurisdiction of the Ministry of Mines to the Ministry of Industry II. Under this arrangement, the influence of the technicians who staff MOC is likely to be diminished by that of the bureaucrats who run the Ministry. MOC personnel are now expected to be less accessible to representatives of foreign oil firms, and some

observers predict that this will slow future negotiations for new contracts.

Outlook

Burma has good prospects for further development of its small onshore oil potential. Prospects for offshore oil development cannot be determined until more exploratory drilling is done. The government is likely to continue to find foreign sources of loans to develop the oil industry. While Burma will still resist increased foreign participation in the onshore oil development effort, it appears likely that foreign oil operators will continue to be cautiously welcomed into offshore work.

PAKISTAN

Pakistan's oil potential does not appear particularly bright, based on exploration work already done. Proved oil reserves are estimated at only 75 million barrels, while production averages 10,000 b/d, well below domestic requirements. Extensive reserves of natural gas have been found and more aggressive exploration could prove up additional gas as well as oil reserves, especially in the Baluchistan Basin. Although current political difficulties are inhibiting exploration and development, we believe that the operating climate for foreign oil firms is not a major factor in Pakistan's potential as an oil producer.

Geological Prospects

All of Pakistan's current oil production comes from six fields located in the northern part of the Indus Basin, and exploration is under way elsewhere in the Basin (see map, page 30). In 1976, for example, the Pakistani Government gave extensive publicity to the location of oil deposits in the central Indus Basin. Although only preliminary surveys have been done, the state-owned Oil and Gas Development Corporation (OGDC) optimistically estimates that the find contains oil reserves of 200 million barrels and gas reserves of 4 trillion to 5 trillion cubic feet. Private petroleum industry sources, however, believe the field to be gas condensate rather than crude oil with gas.

The Makran Ranges of the Baluchistan Basin, well west of the oil activity in the Indus Basin are just beginning to be explored. Although the geology of the area has not been thoroughly studied, there are indications that certain structures in the Makran contain trapped oil. The Marathon-Union Company, presently the only foreign firm operating in the area, is drilling both onshore and offshore.

Amoco has the largest exploration effort in Pakistan with concessions totaling 77,700 square kilometers, mainly in the Potwar Plateau area. Texasgulf holds two concessions in Sind, the southern portion of the Indus Basin. Seismic studies done by the company show two promising deep oil structures, and drilling is expected to begin within the next few months. Texasgulf will also be drilling an exploratory well in a third concession in the Karak area of the North-West Frontier Province later this year. By and large, these are small efforts reflecting a general lack of confidence that large amounts of oil remain to be located in Pakistan.

Pakistan has had more success in finding and developing natural gas than oil over the past 15 years. Gas production figures are not announced by the government but an estimated 190 billion cubic feet were produced in 1976. Gas reserves are estimated at 21 trillion cubic feet with the Sui Field in eastern Baluchistan (8 trillion cubic feet) and the Mari Field in North Sind Province (4.1 trillion cubic feet) accounting for the bulk of reserves. Other reserves are associated with the Potwar Fields and in small scattered fields in the Sind. Many of the Sind gasfields, while not fully tested, are known to contain lower quality gas.

Capabilities and Constraints

OGDC functions both as negotiator of exploration agreements with foreign operators and as an exploration and development company. The Pakistani Government has welcomed foreign companies in the search for gas and oil and favors joint ventures involving the equity participation of an international oil company, a foreign financial institution, and OGDC. The government's attitude is dictated by OGDC's limited capabilities for independent exploration and development and its high dependence upon foreign

sources for equipment, technology, and training. Although state financial support for OGDC has increased greatly in the past two years, funding remains limited. OGDC still has difficulty meeting the drilling and development goals set forth in the annual state plan.

Another constraint on exploration and production in Pakistan is the political turmoil associated with the removal of Prime Minister Bhutto as head of the government by the military. While the new military government is continuing most of the policies of the Bhutto regime, foreign oil operators are uncertain as to its permanence and cannot expect new initiatives until the political situation stabilizes.

Even before the fall of the Bhutto government, foreign oil companies had become apprehensive over future operations in Pakistan. In 1976 the government announced new changes in the bureaucratic structure for petroleum exploration and development. A new organization, the Pakistan Petroleum Commission (PPC), was to be established to take over the petroleum functions now in the Ministry of Fuel, Power, and Natural Resources and absorb OGDC. Under the present arrangement, the Ministry serves as the concession-granting and regulatory agency. The oil companies feel that they have been treated on a reasonably equal basis with the OGDC. The new decrees were never implemented because of the change of government. Nevertheless, the companies feel that if the PPC comes into being it will receive preferential treatment in the awarding of concession rights and in the application of exploration and development regulations.

Outlook

At present we rank Pakistan's oil potential as extremely limited, although further exploration—especially along the coast in the Makran Ranges area—could lead to substantial increases in the reserve base. The prospects of adding to already significant natural gas reserves are far better. Most of the contending parties in Pakistan's current political turmoil appear to recognize the role of foreign oil exploration and development companies in lessening the country's dependence on oil imports. Any new government is likely to provide the incentives to keep foreign operators in Pakistan.

BANGLADESH

Although Bangladesh has yet to find oil, it does have substantial reserves of natural gas, some of which have been exploited since 1960. Drilling of promising additional onshore and offshore areas still goes forward even though some operations are complicated by boundary disputes with India and Burma. Foreign oil companies have been active offshore since 1974 and are now welcome onshore as well although areas with the best potential have been reserved for the government.

Geological Prospects

Bangladesh's oil and gas prospects center on the Assam Basin in the northern half of the country and on the Arakan Coastal Belt to the south, which extends into Burmese territory (see map, page 30). Gas prospects are most promising. Recent estimates of potential gas reserves run between 18 trillion and 25 trillion cubic feet with the higher number apparently including an optimistic guess of the potential of offshore fields.

Gas offtake from the country's four producing fields was nearly 30 billion cubic feet in 1976. Three of these fields are in northeastern Bangladesh. Further appraisal drilling of the Bakhrabad Field in the northeast is planned. Recent information, however, suggests that geological faults divide this field into three parts, with significant quantities of gas only in the central section. As with the older fields, the methane content of the Bakhrabad Field is more than 94 percent. Gas has also been found at Hijla-Muladi and Begumgani; further drilling is planned although these fields are probably only minor.

In late 1976, Union Oil Company discovered gas 80 kilometers offshore in the Bay of Bengal. The company has not yet decided whether to exploit this find, nor whether to conduct further exploration. No other commercial deposits have been found offshore.

Capabilities and Constraints

The Bangladesh Oil and Gas Corporation (Petrobangala), a government agency, deals with exploration and development and regulates foreign activity. Its operational subsidiary, the Taila Sandhini Company, conducts onshore exploration with foreign technical assistance. The firm has drilled six wells onshore in the past two years using Soviet equipment and assistance, which the government has found unsatisfactory on technical grounds. Production testing on one of these wells was recently undertaken by an American firm. West Germany also provides technical assistance, and Norway may do so.

Taila Sandhini was negotiating for the purchase of drilling rigs as of last May. It reportedly prefers American equipment to the Soviet or Romanian rigs, but has had difficulty financing the purchase. The government has signed production-sharing contracts for offshore exploration with six foreign companies; costs are to be recovered from the first 30 percent of output. In July 1976 the government offered onshore concessions covering much of the country and invited joint ventures in these areas of Petrobangla's operational franchise except where there are known fields or current exploration.

Offshore contracts with two foreign companies include areas claimed by India and Burma. The unresolved boundary problem with India reportedly made it more difficult for an American company to find an investment partner and was probably one factor in its decision to abandon its area. The Japanese concession area has been reduced because of the Burmese claim.

Evaluation of the Bakhrabad Field, meanwhile, has been delayed because the responsible US company has had trouble arranging financing.

Outlook

Bangladesh's oil and gas potential now appears somewhat less promising than was thought two years ago, although the country clearly has substantial gas reserves. Plans are in train to increase production from already established gasfields. Prospects for the near future depend on further appraisal, especially of the Bakhrabad Field and of the offshore find. Bangladesh has neither the technical nor financial resources necessary to proceed without some form of foreign support, but its relations with foreign companies and international advisers are sufficiently satisfactory to permit exploration and exploitation to continue.

TAIWAN

Taiwan, poorly endowed with energy resources, has been eager to find and develop domestic sources of oil and gas. The state-owned Chinese Petroleum Corporation (CPC) has spearheaded oil exploration activities along Taiwan's continential shelf with the help of US firms. Although CPC plans to step up both onshore and offshore exploration in the near future, prospects for major finds are poor unless activity is shifted to more promising areas in the East China Sea. Foreign firms, however, have been unwilling to operate in such regions in view of Taiwan's conflicting territorial claims with China, Japan, and South Korea.

Geological Prospects

Dependence on foreign energy sources has been the major spur to Taiwan's exploration and development activities. At present, Taiwan has 84 onshore producing wells, almost all of which are gas. Domestic gas production currently meets all of the island's gas needs. Domestic crude production, however, supplies only 2 percent of current oil needs of about 200,000 b/d.

Taipei has eagerly sought foreign assistance in its exploration activities. As an inducement, CPC provides one-half the capital necessary to conduct offshore drilling and any profits from a joint venture are split 50-50 with the foreign partner. Several US companies—including Gulf, Amoco, and Conoco—which had been participating in joint exploration programs recently returned their concessions because of poor results.

Last year, CPC's exploration program called for 20 wells. Of 14 planned onshore wells, nine have been drilled; six were dry and three produced gas. In offshore exploration, five holes were abandoned as dry and one is still being drilled. CPC's emphasis is gradually shifting to offshore drilling; in 1976, the government committed $500 million to a long-term offshore drilling program. This year seven offshore wells will be drilled, one of which has already established an encouraging gas flow. Offshore drilling will be concentrated in the former Amoco concession and in an area off the island's northern coast.

Capabilities and Constraints

Conflicting territorial claims with China and, to a lesser extent with Japan and South Korea, have prevented more active offshore explortion by foreign oil firms. Their reluctance stems largely from fear that drilling activity in disputed areas could provoke a confrontation with Peking. Taipei recently tried and failed to get drilling under way about 160 kilometers north of Taiwan, midway between the island and the Chinese mainland. Foreign firms were unwilling to operate in the area even though Taipei guaranteed full replacement value should a rig be damaged or destroyed. Disputes with the Japanese and South Koreans involve other offshore areas.

THAILAND

Nine years of exploration in Thailand have failed to turn up commercial oil deposits, although significant reserves of natural gas and condensates have been discovered offshore in the Gulf of Thailand (see map, page 38). Negotiations currently are under way to develop gas reserves using World Bank financing and foreign oil company technology. While exploration efforts to date offer little hope of finding commercial oil deposits, the chances for additional gas finds appear excellent.

Geological Prospects

Since Thailand opened its territory to foreign exploration in 1968, it has attracted a number of major oil firms. Onshore exploration showed little promise from the outset, and the onshore leases, held by Gulf and Union, were relinquished after drilling one well on each lease. In the Andaman Sea off the west coast of peninsular Thailand, Exxon and Union drilled 10 dry holes ranging from 1,370 to 3,960 meters deep, in water depths from 490 meters to a record 900 meters. These discouraging results have prompted reports that both companies will give up the search for oil in the Andaman Sea.

Exploration in the Gulf of Thailand has been more extensive as well as more fruitful. Of the roughly 50 wells drilled to date, eight have shown gas and condensate in structures 1,220 to 3,660 meters deep, in water depths of 45 to 75 meters. Union's find is estimated to contain 1 trillion cubic feet of gas as well as substantial amounts of condensate. Under approximately the same geological conditions, Texas-Pacific completed two large gas wells containing more than 2 trillion cubic feet in the past year. The Texas-Pacific discoveries have generated considerable optimism regarding additional gas discoveries.

Capabilities and Constraints

Thailand depends on foreign expertise for developing its hydrocarbon resources. Relations with the companies have been harmonious thus far mainly because crude oil in commercial quantities has not yet been discovered. When the oil leases were negotiated in 1968, contract terms called for Thailand to receive a 12.5-percent royalty and 50-percent profit tax on total crude production. After company cost deductions, however, the government would net probably less than 50 percent of gross crude revenues. In view of the recent tightening of contract revenue terms in Malaysia and Indonesia, it is likely that, should large enough crude discoveries be found, the government would press the companies for a larger share of revenues.

Gas discoveries were not anticipated in the original contracts. Consequently, the government has held extended talks with Union since the beginning of 1976, attempting to negotiate a wellhead price sufficiently attractive for Union to invest in gasfield development. Plans have been made to construct a 600-kilometer subsea pipeline from Union's field north to Bangkok. Another 180-kilometer pipeline would be needed to connect the Texas-Pacific discoveries to the south. Total cost of the pipeline will be about $500 million to $600 million. World Bank financing is being sought for the major portion of the projects, and some commercial borrowing is also likely. The target date for completion is in 1981.

Outlook

Given the magnitude of past exploration efforts and the geology encountered, Thailand appears to have little or no potential as an oil-producing country. With continued exploration, nevertheless, more gas and condensate discoveries are reasonably assured. The Thais are eager to start on the gas pipeline project in the interest of reducing oil imports, currently running at some $800 million per year. Existing gas and condensate discoveries already are sufficient to offset about 25 percent of oil imports. Agreements with the companies will probably be concluded in the near future.

PHILIPPINES

The Philippines, after a long series of unsuccessful drilling efforts, now appears to have discovered oil in commercial quantities. Previously, drilling programs by foreign and domestic oil companies have moved very slowly, despite apparently favorable geological conditions. Recent discoveries and liberal government incentives are now accelerating the still very slow rate of exploration. Prospects of proving up enough reserves to support significant production before the early 1980s are not especially bright.

Geological Prospects

Philippine geological structures have long been believed to hold oil-bearing deposits. The extended archipelago possesses striking geological similarities to neighboring Indonesia and the north Borneo states of Malaysia. The large number of tertiary sedimentary basins located on land as well as on the western continental shelf are likely to contain numerous but not large oil-bearing reservoirs and traps.

Although exploration dates back to the turn of the century, it was only during the 1950s and early 1960s that seismic surveys were undertaken and a number of exploratory wells were drilled, largely in the northern Luzon Cagayan Valley Basin. In the early 1970s, interest in offshore exploration picked up and 129,500 square kilometers were leased by some 40 companies, many local, under concession agreements. Nevertheless, drilling rates remained low; in 1974 and 1975, 16 holes were drilled, none of which were successful.

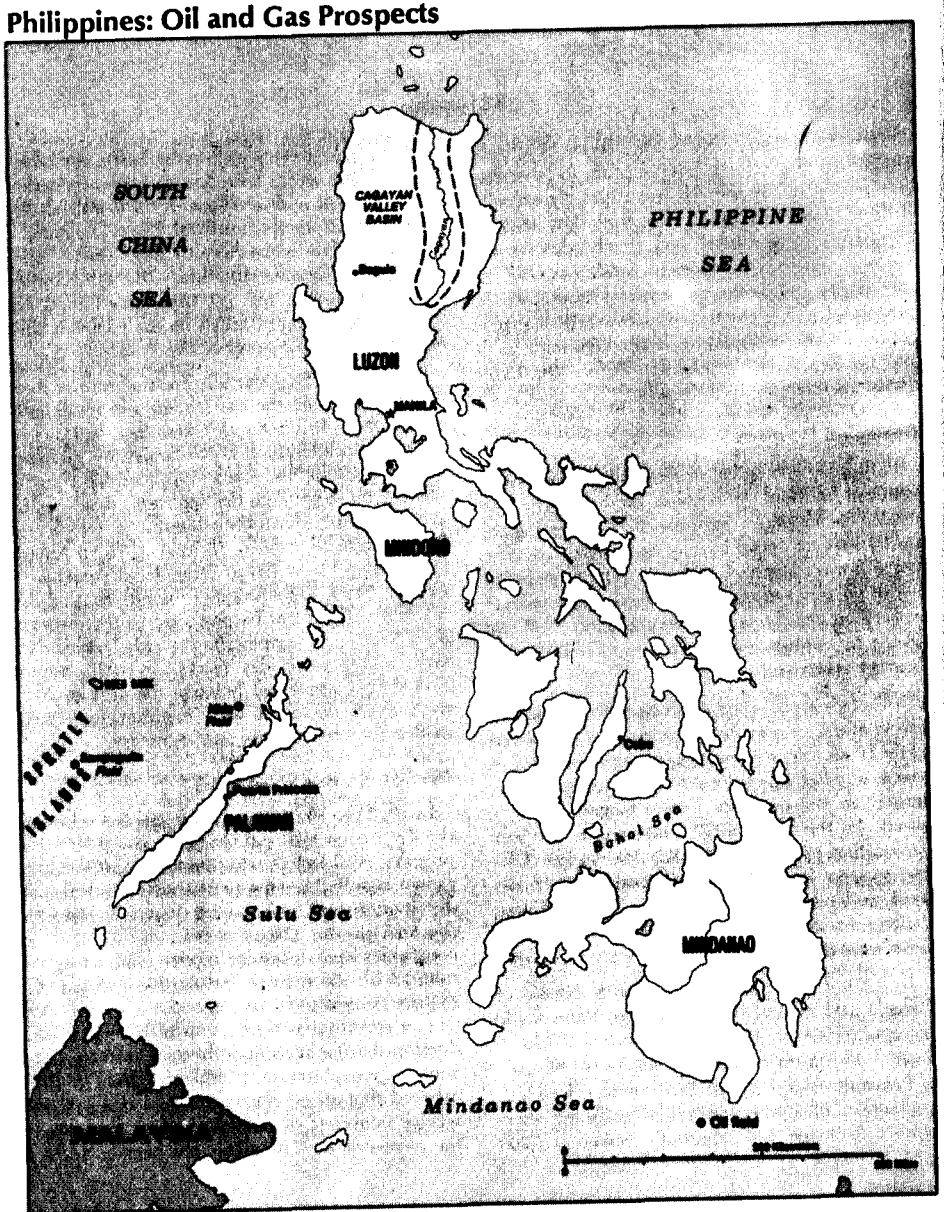
In 1976 Cities Service along with Husky of Canada and several Philippine companies made the country's first significant discovery (Nido I), located 45 kilometers off the northwestern coast of Palawan. At a depth of 2,890 meters, well logs and cores indicated porous reefal limestone reservoirs; a drill stem test reportedly flowed at 7,200 b/d. A confirmatory well to the north, completed later in the year, was disappointing, revealing only traces of hydrocarbons. A third well, drilled in July 1977 to the south of Nido I, yielded a strong oil flow—the best to date—in a highly fractured carbonate structure. Although commercial viability has not yet been ascertained, the reaffirmation that oil exists on the Palawan Shelf should spur exploration in the area.

Exploration last year also focused on the Reed Bank, located on the eastern edge of the Spratly Island chain in the South China Sea. Jurisdiction over this atoll has long been claimed by Vietnam, China, Taiwan, and the Philippines. To press its claim, Manila granted drilling rights to a Swedish group (Salen), controlling interest of which was later bought by Amoco. In April 1976 an American-owned drill barge completed one well, despite State Deparment admonitions that US operators would not be protected in the disputed area. This well (Sampaguita I) yielded oil condensates and natural gas shows. In 1977 Amoco drilled two additional holes in the area to complete the terms of its work contract. Both were drilled to 3,660 meters and were dry.

Capabilities and Constraints

In 1973 the Philippine Government established the Philippine National Oil Company (PNOC) to promote oil development. Since then, PNOC has grown rapidly, moving extensively into refining, distribution, and, to a modest degree, exploration (limited to the Cagayan Valley). Foreign oil companies operate under service-contract agreements with the Energy Development Board that require commitment to a specific work program over a specified period. With discovery, a production-sharing agreement becomes effective. To encourage exploration, President Marcos in 1975 decreed that all oil concession holders move into service contracts or relinquish their holdings to the government. The effect has been to force a

Philippines: Oil and Gas Prospects



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plethora of small speculative, undercapitalized local companies to seek foreign company capital and technology. The Marcos regime clearly recognizes that foreign investment is essential for upstream oil development. Even with recent government incursions into downstream activities, the Philippines will continue to offer attractive terms for foreign oil operators.

Outlook

Geological formations and proximity to oil-producing areas strongly indicate potential for commercially exploitable oil resources in the Philippines. Current government policies coupled with recent finds off the Palawan Shelf are likely to encourage new exploration activities at a rate well above past years.

SOUTH KOREA

South Korea's efforts to find domestic oil reserves have been stymied by negative results in its onshore drilling and by disputed claims to still largely unexplored offshore areas. Recent Japanese ratification of a joint exploration treaty should stimulate exploration; problems with China remain.

Geological Prospects

Commercial quantities of crude oil have never been found in South Korea. Although a small deposit was discovered in late 1975 near Pohang on the southeastern coast, further exploration indicates that the quantity is insufficient for commercial exploitation. A 1968 UN geological survey indicated considerable oil potential in the Asian continental shelf extending from southern South Korea along the coast of China to the Tonkin Gulf. Concessions were granted to several American oil companies, but exploration has lagged because of territorial claims by Japan and China. Four exploratory wells were drilled in 1972 and 1973 in the Yellow Sea before the US Government persuaded the oil companies to stop operations in the contested area. All were dry holes, although traces of natural gas were observed.

Capabilities and Constraints

As most Korean oil potential is in offshore areas, the most important barrier to exploration has been the conflicting claims problem. In the Yellow Sea, the South Korean claim is based on the equidistance criterion and thus extends halfway to China. The Chinese, on the other hand, favor the 100-fathom criterion that would give them a larger portion of the continental shelf. The Koreans have offered to negotiate the difference, but China refuses to discuss them other than to declare Korean claims invalid.

South of Korea in the East China Sea the major contention has been with Japan, although China disputes the claims of both countries. In 1974 a Korea-Japan treaty establishing a large joint exploration area was signed. The Japanese Diet delayed ratification until June of this year, and no drilling has yet occurred. The American oil consortium that holds the Korean concession may begin exploratory drilling next year. Any oil found will be shared equally with Japan.

The Koreans have begun to develop a domestic exploration capability. A private Korean firm employing only Korean technicians undertook the original exploratory work leading toward the Pohang discovery. The firm went bankrupt before the discovery was made, however, and the government took over the project. Although the Korean CIA was placed in control of the operation, it has since abandoned the project.

Offshore exploration has been conducted entirely by major international oil companies through concessions from the Korean Government. The Koreans have indicated, however, that if exploration in these areas continues to lag after Japanese ratification of the joint venture zone, they would attempt to develop their own offshore exploration capability. This capability could be gained by contracting for foreign equipment and expertise. The expense and risk would be considerable, and the necessary funds have not been budgeted in the current Five Year Plan (1976-81).

Outlook

The outlook for discovery of oil in and around South Korea has been diminished by the poor results of recent exploration. Major areas remain to be explored, however. Diplomatic considerations are the main impediment to such explora-

tion. Although ratification of the Japan-Korean continental shelf treaty is a big step, strong Chinese opposition could hinder exploration. Should oil be discovered, the absence of relations between South Korea and China could present major diplomatic problems.

VIETNAM

The favorable prospects for Vietnamese oil production, which came to light in the waning months of the war, remain simply prospects. US-connected companies were forced to give up a promising exploration program in offshore South Vietnam when the North took over in April 1975. In the past several months the Vietnamese Government and its national oil company, Petro Vietnam, have signed preliminary exploration agreements with French, Italian, and German firms. Details have not been worked out and no further exploration has taken place. Without Western participation Vietnam stands little chance of developing what oil potential it does have.

Geological Prospects

Petroleum exploration in Vietnam is at best embryonic. The presence of hydrocarbons on the continental shelf of southern Vietnam is undisputed, but reserves cannot be quantified until exploration resumes. Foreign oilmen speculate, however, that several fields of 100 million barrels or more may exist. This could imply eventual production levels on the order of 270,000 b/d.

The exploration program was only eight months old when the North took over the South in April 1975. The previous South Vietnamese Government had awarded eight concessions for petroleum exploration on its continental shelf to four companies or consortia in 1973. A Mobil-Kaiyo consortium discovered oil in its first 3,000-meter well completed in March 1975, about 180 kilometers southeast of Saigon. The well tested 2,400 b/d of 35° API gravity crude and some gas.

Vietnam's most promising prospects are on the continental shelf off the southern part of the country. There is some likelihood that petroleum bearing structures may extend onshore into the Mekong River Delta but no meaningful surveys have taken place there. In the north, the USSR, Romania, and East Germany have been assisting with onshore exploration in the Red River Delta since at least 1967. There have been no indications of any discoveries.

Capabilities and Constraints

The Vietnamese are taking a cautious approach to developing their oil sector. Their caution stems from a lack of knowledge and experience in almost all aspects of the petroleum industry and from ideological concern over the level of non-Communist foreign activity to be tolerated in Vietnam. The North Vietnamese knew almost nothing about the petroleum industry when they took over the South. The few high-level South Vietnamese associated with the industry left when the Communists took over. Moreover, the oil companies apparently took with them all seismic and other technical data. The knowledge gap means that negotiation of complex contracts with infinite permutations and combinations of profit rates, cost writeoffs, production splitting, taxes, and employee compensation becomes even more difficult.

Ironically, the Vietnamese must depend on Western oil companies for almost every aspect of exploration and production. Vietnam itself has neither the technology nor the capital for exploration; nor do its Communist allies. Only the China, the USSR, and Romania have offshore experience, but their scarce equipment is tied up in domestic oil development. In any case, the Vietnamese want the advanced Western technology for its prospects of bringing crude on stream more quickly and efficiently. In this regard they prefer US to European firms because of their superior technology and financial resources and their previous experience in the area.

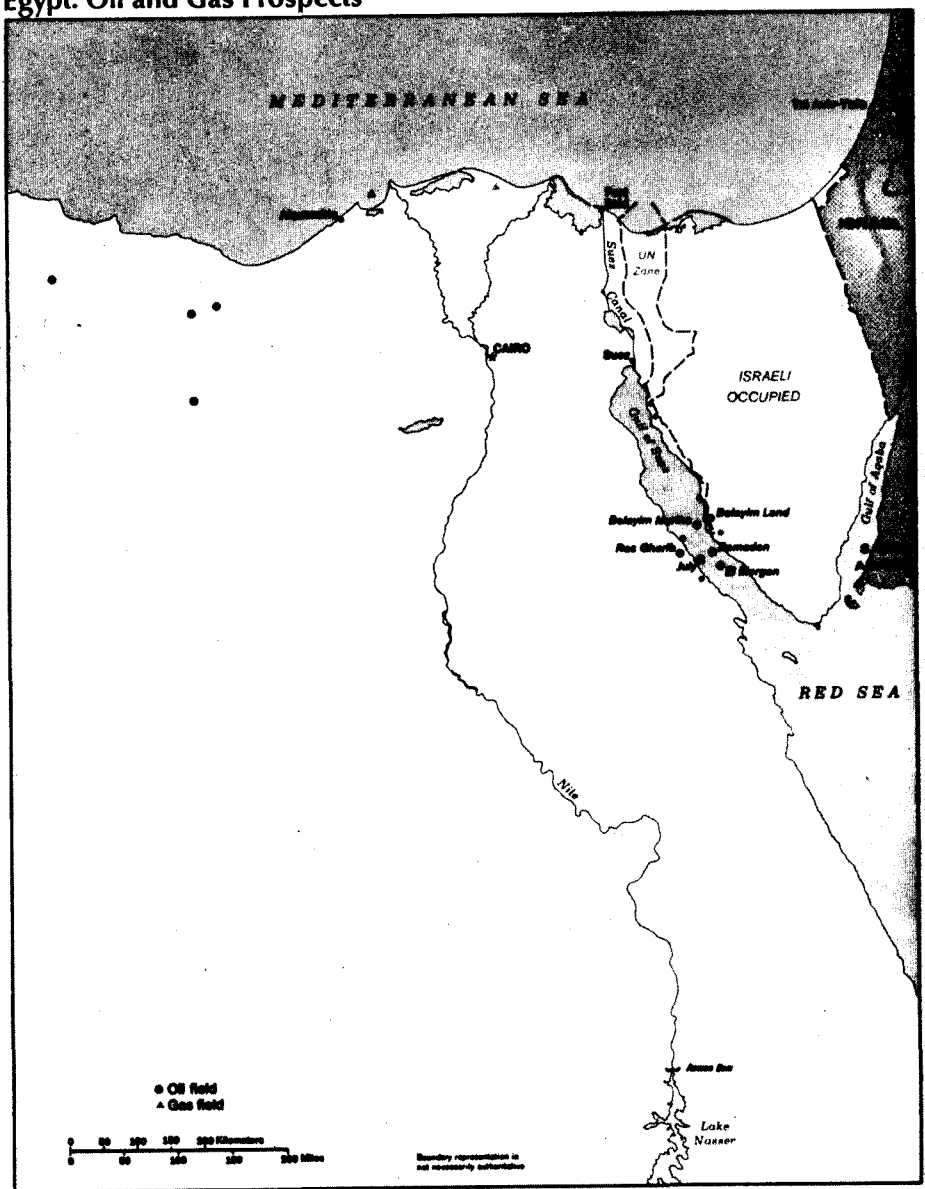
Outlook

It is too early to tell if Vietnam will become an oil producer. The geology of the continental shelf favors hydrocarbon deposits and preliminary drilling showed some promise. Nonetheless, the four test wells drilled so far do not bear out the initial enthusiasm that attracted companies to South Vietnam in 1973 and 1974. More than two years have elapsed since exploration was halted and the contracts rescinded. The Vietnamese will bargain hard with the foreign oil companies—most of which will be reluctant to accept terms less attractive than in Malaysia or Indonesia. The consensus nature of Hanoi's decisionmaking and the ponderous workings of its bureaucracy will also inhibit the development of oil potential in the area. As things now stand, chances of achieving any oil production by 1980 are negligible.

Non-OPEC Middle East, North Africa, and the Mediterranean Area

Chances of finding significant new reserves in this area are generally poor. Only in Egypt and possibly Oman do prospects of major new finds appear probable. Although exploration in some areas of Egypt is proceeding rapidly, it is inhibited in one of the most promising areas, the Gulf of Suez, by the state of relations with Israel. High costs, difficult conditions, and a somewhat chaotic government oil policy have combined to limit company interest in Oman. Exploration in a fairly promising area claimed by both Tunisia and Libya has been halted because of the dispute between the two countries. Elsewhere, poor geological prospects, political uncertainty, and, in the case of Turkey and Greece, territorial disputes limit company interest.

Egypt: Oil and Gas Prospects



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EGYPT

Egypt's oil potential is greater than that of most non-OPEC LDCs. International oil companies generally have a high regard for Egypt's geological potential, particularly in the Gulf of Suez area, where four major discoveries have already been made. They are also attracted by Cairo's long record of good relations with foreign oil companies and by the moderate policies of the Sadat regime. Since 1973, foreign firms have signed more than 30 operating agreements, worth $800 million in investment commitments. At present, Arab-Israeli tensions constitute the major constraint to increased exploration.

Geological Prospects

Egypt's oil industry is heavily concentrated in the Gulf of Suez area. Since oil exploration began 70 years ago under British auspices, all major discoveries have been located in this region. Of the 500,000 b/d that Egypt expects to produce by the end of 1977, more than 400,000 b/d will come from offshore fields in the Gulf of Suez. Three other small producing fields are presently located in the desert west of Alexandria 50 to 100 kilometers inland from the Mediterranean. The Alexandria area is the site of Egypt's only gasfields.

The bulk of Egypt's 4-billion-barrel proved and probable reserves are located in the Gulf of Suez area. Some geologists estimate that less than half the oil in this area has been found; more than two dozen structures remain to be drilled. Further exploration may establish that the Gulf structure trends continue north into the Nile Delta and the Mediterranean Shelf. In the Western Desert, where a rash of oil exploration followed discovery of major Libyan fields in the early 1960s, only small, widely scattered and mainly noncommercial fields have been located. Several of these pools may now be exploitable at today's prices.

One area where oil-bearing potential may have been badly underrated is adjacent to the Libyan border below the 30th parallel. This zone was once reserved exclusively for the Egyptian state oil company and was explored with Soviet technical assistance. Accusing the USSR of employing obsolete seismic equipment and techniques in their exploration efforts, the Egyptians ejected Soviet technicians a few years ago and opened up this area to concession agreements. A more sophisticated search might reveal oil-bearing strata overlooked by the Soviets.

Capabilities and Constraints

Most of Egypt's oil is produced jointly by the Egyptian Petroleum Authority (EPA) and Western oil companies. Typically these partnerships are formed after the foreign partner has discovered oil in a previously awarded concession area. The giant among Egypt's partners is Amoco, coproducer in all but one of the major offshore oil fields in the Gulf of Suez. Phillips operates two small, rapidly declining fields in the Western Desert, and a number of firms, including ENI and Mobil, have participated in operation of onshore and offshore fields in the Sinai Peninsula. Deminex, a West German firm, and Conoco have recently made sizable discoveries in the Gulf of Suez area.

EPA is probably Egypt's most efficient state firm. It is the sole operator of six refineries that process some 200,000 b/d of crude, and it was able to rebuild war-damaged refineries at Suez and to construct one new facility without outside assistance. The firm also operates a number of small fields without foreign assistance and could probably handle operations in most of Egypt's major fields if needed. However, since EPA does not have an independent exploration capability, it would eventually face falling output if its Western partners pulled out or were expelled.

Thanks largely to the administrative and technical skills of its top personnel—especially Oil Minister Hilal—Egypt's state petroleum establishment has avoided most of the organizational and financial constraints that plague other state firms. EPA's relations with its foreign partners are also good. The only change in its relationship with foreign oil companies over the past decade was a shift to production sharing from the 50-50 partnerships established in the 1960s—a transition negotiated amicably over a period of years. Although these agreements will eventually increase Egypt's share of crude produced, the partner company is entitled to a liberal share until its initial investment has been amortized.

Outlook

Despite these many advantages, Egypt's oil industry will face a number of serious problems. The chief hazard is the vulnerability of the Suez area where oilfields have been a pawn in the Arab-Israeli confrontation. The Sinai II Agreement has by no means eliminated all of these handicaps. The Israelis still claim exploitation rights in the eastern half of the Gulf of Suez where the most promising seismic areas are located, and drilling attempts by Egypt's US partners have been harassed by the Israeli Coast Guard. Until a more permanent settlement is secured, there is also the constant threat of another canal closing, a blockade of the Gulf of Suez, destruction of facilities, or occupation of fields.

Israeli harassment of Suez oil operations has caused US firms to scale down estimates of future production. If the entire Gulf of Suez were freely exploitable, Egyptian oil output would almost certainly climb to 1 million b/d by 1980 with an export surplus of about 700,000 b/d. If harassment continues, new production may exceed declining output in older fields by only small margin, limiting 1980 output to 650,000 b/d. Political factors within Egypt are likely to play a much less decisive role. It is possible that the Sadat government may be badly shaken or even overthrown for any of a variety of reasons. However, even in the event of a coup, an abrupt reversal of Egypt's long tradition of good relations with foreign oil companies would be strenuously resisted by EPA officials.

OMAN

The Sultanate of Oman is a major producer of crude oil, ahead of Ecuador and Gabon among the OPEC group. Oil production—370,000 b/d last year—comes exclusively from fields in northern sections of the country. These fields peaked in 1976 and output is expected to drop sharply in the next few years unless more oil is found and developed. The best prospects for discovering new oil lie in southern Dhofar which could add substantially to existing proved and probable reserves of 6 billion barrels. The government also believes additional oil will be found offshore in the Straits of Hormuz.

Geological Prospects

Oman's crude oil production comes almost entirely from fields in the north central section of the country. The first exploitable oil was discovered at Yibal in 1962, followed closely by finds at Natih and Fahud in 1964. In 1970 the Al-Huwaisah Field was discovered and in 1975 three new fields—Ghaba North, Qarn Alam, and Saih Nihaydah—were put into production. All of these fields are mature and oil flows are dwindling. Despite the introduction of costly secondary recovery projects—primarily waterflooding—output from these fields is expected to decline to about 250,000 b/d by 1980.

Oman's major hope for new oil discoveries is in the south, in the Dhofar region. Production in the area, however, would be expensive because the oil-bearing strata are not uniform. Moreover, like crude from the northern fields, oil discovered so far in the Dhofar is heavy and has a high sulfur content, which will add to extraction costs. A costly pipeline would also have to be built over rugged terrain to bring the oil to the sea where a harbor and offshore loading facilities will have to be built. Although no commercial finds have yet been made, the government believes Dhofar reserves could be extensive. Foreign oil companies are less sanguine and are demanding special terms before investing in the Dhofar region due to high costs and the risk involved.

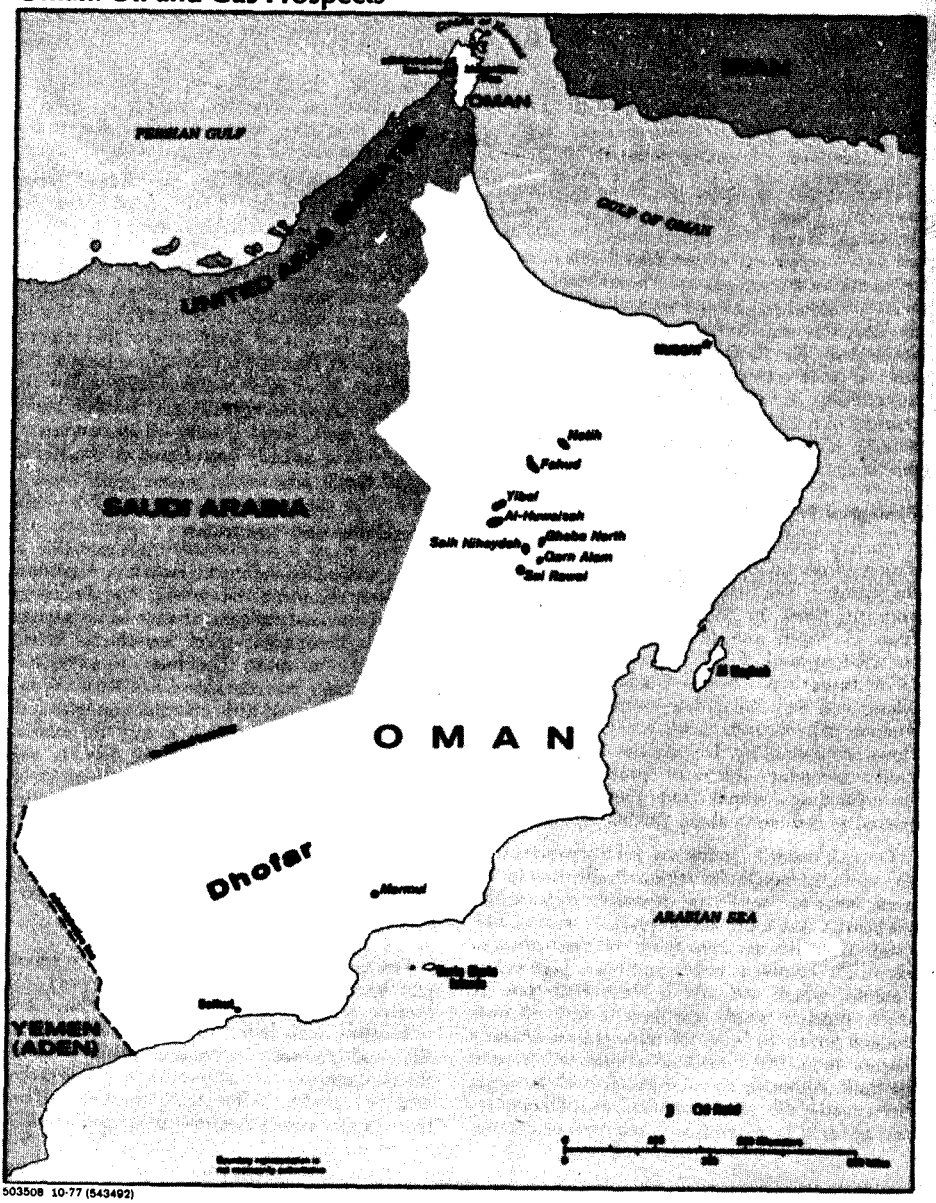
In addition to this activity, some offshore exploration is under way and the government is encouraging more. In 1973 ELF-Erap obtained the rights to explore 7,000 square kilometers of the Straits of Hormuz off the Musandam Peninsula—they have had one successful strike that they claim could eventually add 100,000 b/d to Omani output. Good quality oil in commercial quantities has already been found on the Iranian side of the Straits.

Capabilities and Constraints

The Omani Government lacks the experience to effectively direct oil policy. The Petroleum Minister has had little experience in oil matters, and the government relies heavily on foreign consultants to make decisions. Consequently, there has been considerable confusion in awarding concessions and little coordination within the government on oil matters. Except for exploration in Dhofar, the government lets its Shell partner make decisions for the Petroleum Development Oman (PDO), Oman's largest concessionaire and only oil producer. The Sultanate maintains a 60-percent ownership in PDO while Shell, Compagnie Francaise des Petroles (CFP), and Partex hold 34-percent, 4-percent, and 2-percent shares, respectively.

The Government of Oman is trying to encourage independent exploration using production sharing as an incentive. Agreements have been successfully concluded with the owners of the ELF and Quintana concessions, whereby initially the oil companies are allowed a 40- to 50-percent share of profits. After the companies recover their capital costs 80 percent of oil profits will go

Oman: Oil and Gas Prospects



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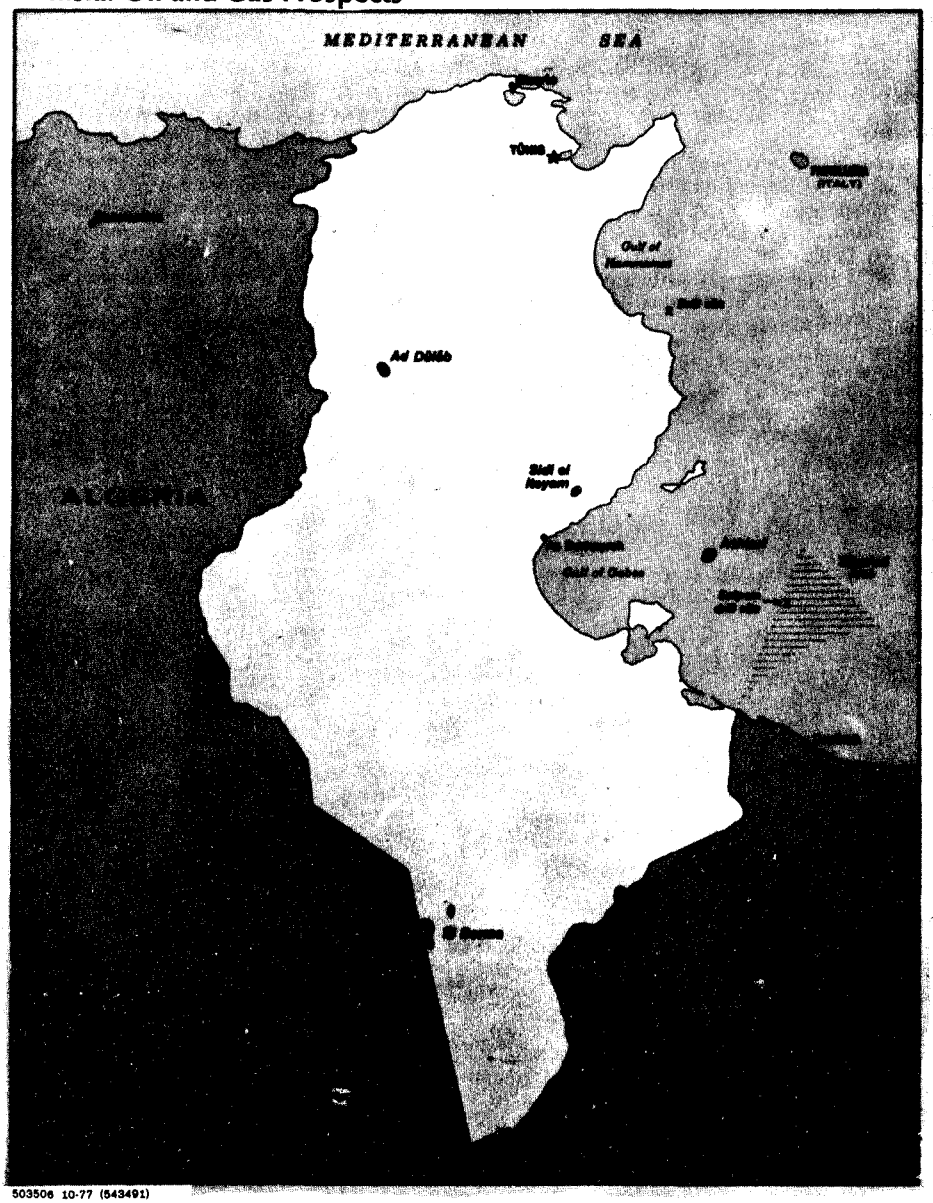
to the government and 20 percent to the companies.

Outlook

Financial considerations will play a major role in setting the pace of oil exploration in Oman. The government has stated it is willing to finance exploration and eventual development of the Dhofar fields even though it already is short of funds. Without company participation Oman is probably counting on aid from Saudi Arabia to finance the Dhofar program. Saudi Arabia recently raised its aid commitment to Oman to almost $300 million, however, and would be reluctant to provide large amounts of additional aid to underwrite the exploration and development of Dhofar oil. In any event, prospects for finding accessible onshore oil deposits in Oman are remote. New discoveries are likely to follow the pattern of those found in the recent past—small fields with high development costs. Offshore finds—even if they prove large—will be expensive and time consuming to develop, adding little to Oman's output before the early 1980s.

Tunisia: Oil and Gas Prospects



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TUNISIA

Tunisia, a minor oil producer since the early 1960s, has limited prospects for expanding output from traditional producing areas. At the same time, exploration and exploitation of a promising offshore tract—containing upwards of 5 billion barrels of oil—are being hindered by a territorial dispute with Libya. Lacking expertise of its own, the government is actively encouraging foreign assistance in developing its oil resources.

Geological Prospects

Almost all of Tunisia's 100,000 b/d of oil production comes from two fields, the onshore field at El Borma in southwest Tunisia, discovered in the early 1960s, and the Ashtart Field in the Gulf of Gabes, discovered in 1974. Two smaller onshore fields, Sidi el Iteyam and Ad Dulab, currently produce insignificant quantities of oil. Altogether, existing wells are likely to be exhausted in five to 10 years. At the El Borma Field, for example, output has declined sharply in recent years, dropping 50 percent since 1973.

Prospects for finding additional quantities of onshore oil are not bright. Western firms—mainly French and Italian—already have made exhaustive surveys of existing tracts and results have been disappointing. As a consequence the search for oil has shifted entirely offshore. In addition to drilling stepout wells from the Ashtart Field, operations have begun farther north in the Gulf of Hammamat, where a French company reportedly has made a discovery. US companies working in adjacent waters have failed to find commercially exploitable oil but are continuing their search. Company officials believe the area could produce some 20,000 b/d by 1980 if finds are made soon.

The continental shelf area bordering Libya has the greatest potential, containing as much as 5 billion barrrels of recoverable reserves. Tunis, however, is wrangling with Tripoli over ownership of the area which lies 100 kilometers north of the Libyan coastal town of Zuwarah. Tensions between the two countries sharpened when Saipem—an exploration subsidiary of ENO of Italy working for the Libyans—began drilling in disputed waters. An oil strike, which Tripoli announced as a major find, was made in that area in January 1976.

Capabilities and Constraints

The territorial dispute is the major impediment to identifying and developing portions of the continental shelf's reserve potential. Libya maintains that the offshore boundary line follows a northwesterly path from the coast, placing Saipem's drilling operation in Libyan waters. Tripoli has offered to share information on the site with Tunisia and reportedly is willing to jointly explore and develop the area until the issue is resolved. Tunis for its part maintains that the boundary line follows the natural northeasterly arc of the Tunisian-Libyan border as it approaches the Mediterranean coast and, therefore, the strike is in Tunisian territory.

Apart from the territorial dispute with Libya, there are few political constraints to oil company operations in Tunisia. The government has a history of actively encouraging cooperation with foreign oil companies. The government negotiates arrangements with the companies on an ad hoc basis and is willing to cut almost any kind of deal to accommodate the companies. For example, investment guarantees are given, rapid amortization of drilling costs is permitted, and companies are allowed to keep relatively large shares of any oil found.

Outlook

Tunisia is never likely to become a major oil producer. Over the next five years or so offshore production in Tunisian waters could permit an exportable surplus in the range of 100,000 b/d. To increase output much beyond that level, a favorable settlement of the boundary dispute with Libya must be made and drilling to prove out the potential of the area has to be accomplished.

Syria: Oil and Gas Prospects

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SYRIA

Syria cannot maintain present crude oil output of 200,000 b/d without adding appreciably to its reserve base. Recognizing this, the Asad regime is soliciting foreign expertise to help bolster the country's oil potential. Administrative delays and increasing political instability, however, continue to inhibit Western participation and investment leaving the Syrian operations largely in the hands of Soviet and East European firms.

Geological Prospects

Proved and probable reserves are currently estimated at about 2 billion barrels. Most reserves are located in five fields in northeastern Syria, of which four (Karatchuk, Suweidiyah, Rumeilan, and Jubaisseh) are being actively exploited and another (Hamza) is being explored. Suweidiyah came into production in 1968 and now produces slightly more than half of Syria's output. Aside from Hamza, apparently a fairly small field, it seems that most of the reserves of the producing fields have already been defined.

The Asad government has set aside 25,000 square kilometers of potential oil bearing land for the state-owned Syrian Oil Company and opened another 50,000 square kilometers to exploration by foreign firms. French, Romanian, Yugoslav, Soviet, and Hungarian teams are currently undertaking geophysical surveys and exploratory drilling at a number of onshore tracts in northeastern Syria. The only recent strike, however, was made by the Syrian Oil Company in March 1976 near Habari in central Syria. The initial wave of enthusiasm died down quickly, however, and it does not now appear that any significant recoverable reserves were added to the Syrian base.

The most promising geological areas for new discoveries are offshore in the Mediterranean. The very limited exploration effort in that area, however, has been disappointing. A US oil company, Tripco, signed an exploration agreement for a 4,500-square-kilometer parcel off the Mediterranean coast in 1975 but abandoned its search after a year.

Capabilities and Constraints

Syria's stringent Baathist ideology and chronic political instability are important constraints to exploration of the country's limited oil potential. Western firms were driven out during the early 1960s and subsequent efforts have been left largely to Soviet and East European firms, which lack the expertise needed for offshore work. Although Asad is now willing to deal with Western companies, basic obstacles remain in attracting the type of Western investment in the oil industry the Syrians now need. US and West European firms, for example, would require an improved operating environment, including lessened government controls, before making major financial commitments. The threat of political instability in Syria has dampened company interest.

Some qualitative progress can be expected within the Syrian oil industry over the next few years. Dissatisfaction with East European petroleum exploration technology and techniques, for example, has prompted Damascus to insist that even these firms use Western, particularly US, equipment. The Syrian Oil Company is also purchasing US seismic equipment and providing intensive training programs for its personnel in the United States in the hope that the country's oil potential can be more carefully and systematically appraised.

Outlook

Without increased Western involvement Syria's oil production outlook is not particularly bright. The government has already announced a 10-percent production cutback for next year because of a sharp erosion in the reserve to production ratio at producing fields. Unless new reserves are identified and defined soon further cutbacks will be necessary; perhaps reducing Syrian output to only 150,000 b/d or less by 1980.

TURKEY

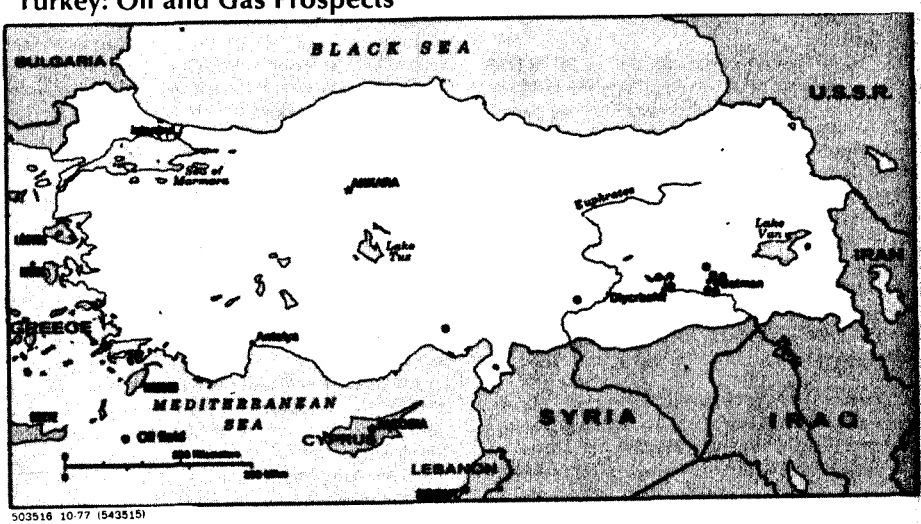
Turkey's crude oil output, which covers 15 to 20 percent of domestic oil requiremets, has declined 27 percent since 1973 and now amounts to only 51,000 b/d. Ankara hopes to reverse the decline but probably will be unable to do so. Tough government regulations are undercutting foreign company interest in exploration, while financial and technical constraints impede operations of the government-owned oil company.

Geological Prospects

Most of Turkey's commercially exploitable oil deposits are located in southeastern Turkey, near Batman and Diyarbakir. All production is onshore. Although small new deposits continue to be found near traditional producing areas, the most promising sites for new finds are Antalya on the Mediterranean and Lake Tuz in central Turkey. Onshore exploration carried out north of the Sea of Marmara and along the Black Sea coast has turned up only noncommercial finds. Total onshore reserves are estimated by foreign companies at only 100 million to 200 million barrels.

Offshore areas appear to have more potential but this cannot be quantified without further exploration. Some known Black Sea deposits, difficult to exploit by present methods, may become available in to five to 10 years with new techniques. Although parts of the Marmara and Aegean Seas have been surveyed with negative results, work there is not finished. Exploration of much of the Aegean probably will have to await

Turkey: Oil and Gas Prospects



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resolution of the Greek-Turkish territorial dispute.

Capabilities and Constraints

The Turkish national oil industry is engaged in all phases of oil operations from exploration to marketing. It is dominated by the Turkish State Petroleum Company (TPAO), which produces about 40 percent of total crude output. TPAO's proficiency at transporting and refining oil is generally adjudged sufficient for Turkey's needs, although not equal to that of Western firms in Turkey. In exploration and production, its performance is seriously hampered by budget constraints, personnel deficiencies, and obsolete equipment. Almost all commercial finds in Turkey have been made by foreign firms. TPAO, which has first priority for new leases, comes under periodic attack for holding more leases than it can reasonably develop, thus keeping many new fields out of production. TPAO has no offshore drilling capability.

TPAO reportedly has been in financial straits for more than a year and, as a result, has been forced to postpone needed development investment. On paper, petroleum development has been accorded high priority, but TPAO probably has been the victim of interministerial squabbling over spending. In any event, Turkey currently has a severe shortage of foreign exchange and doubtless will be forced to adopt austerity measures in order to get assistance from the IMF and other lenders. Ankara might decide to cut TPAO's budget for imported investment goods, which last year included $79 million for items related to exploration and production.

Another frequently cited barrier to increased oil production is the dispute with Greece over the continental shelf of the Aegean. Conflict began in November 1973, when the Turkish Government granted exploration licenses to TPAO in an area west of the Greek islands of Lesvos and Khios. Greece claims that its islands (more than 3,000) have their own continental shelf rights, while Turkey maintains that the continental shelf should be divided by a centrally located fault line, with exceptions only for the 354 inhabited Greek islands. Judging by the unhurried pace at which Ankara is exploring the undisputed areas, even a final settlement favorable to Turkey would not lead to an increase in Turkish production for at least several years.

Government taxation policies are another major constraint on the activities of foreign and domestic oil companies in Turkey. Ankara imposed a $7 per barrel tax to prevent windfall profits after the 1973 OPEC oil price increase. The government also levies a whopping 25-percent tax on all project expenditures in Turkey. The windfall profits levy, on top of previously existing taxes, prevents recovery of exploration and development costs from new wells and has effectively stifled foreign exploration activities for the past three years. The companies cite it as a major reason for the decline in production.

Outlook

Turkish oil production probably will continue to decline until government tax and price policies are altered. Existing fields are being depleted, and exploration has fallen off sharply in the past three years. Even with government incentives, production could not regain the 1973 level of 70,000 b/d for several years. Although government claims are astronomical, estimates of reserves made by oil industry specialists are small. At 200 million barrels, onshore reserves would not last a year at the current rate of consumption. Offshore reserves may well be considerably larger, but their potential cannot be realized for many years.

Greece: Oil and Gas Prospects

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GREECE

Greece now imports its total oil requirements of 170,000 b/d and expects to produce only 25,000 b/d of crude in 1979. While the government's hopes of finding large reserves have not been realized, Athens is committed to continue exploration. To that end, Parliament recently passed legislation to speed up licensing of concessions and to spell out the terms under which foreign oil companies may operate. The terms of the new law appear too stringent to provide much push to foreign company interest in Greece, given its limited oil potential and its territorial dispute with Turkey over some of the most favorable areas.

Geological Prospects

Greece has undertaken a fairly extensive oil exploration program, but findings to date have been disappointing. The most successful venture has been the discovery in 1975 of the Prinos Field near Thasos Island in the northern Aegean Sea. The field has reserves estimated at between 63 million and 400 million barrels. Peak production is expected to be about 25,000 b/d starting in 1979. Prinos oil reportedly is heavy, of low quality, and difficult to handle because of its corrosive properties. The only other commercially exploitable find thus far is an estimated 2 million barrels near Prinos in the South Kavala Field.

Exploration of other portions of the northern Aegean has resulted in dryholes or noncommercial wells. Onshore drilling has been disappointing. The Romanian Prompetrol Agency continues to drill in the Nestos River Delta in northern Greece but has found only noncommercial deposits. Two exploratory wells in other parts of northern Greece were abandoned in 1974.

The Greeks plan to continue exploring onshore and in the Aegean and are currently drilling near Prinos in the Maronias Field. Preliminary surveys indicate this field may contain reserves up to 200 million barrels. The government also has allocated funds this year for geological surveys in the Ionian Sea, where Greek officials believe the geological structures offer better long-term prospects than those in the Aegean.

Capabilities and Constraints

Greece is totally dependent on foreign companies for both oil exploration and production. To help speed exploration and eliminate potential conflicts with foreign-owned oil firms the government recently passed new legislation governing their operations. One of the main provisions permits the Ministry of Industry and Energy to negotiate contracts with concessionaires without each agreement having to be ratified by Parliament. Industry representatives believe this provision will break the current logjam of 55 concession applications, 36 of which are from US firms. Other provisions appear too stringent to attract much new foreign interest. Under the tax code, for example, Athens receives 65 percent of net income after development costs have been recovered. If production levels go above 200,000 b/d, the government share increases to 80 percent of the additional amount.

Aside from the problem of attracting sufficient foreign interest, Greece has delayed plans to explore parts of the Aegean because of the boundary dispute with Turkey. Greece claims that its islands represent an extension of the continental shelf, while Turkey maintains that the shelf should be measured from the Greek and Turkish mainlands. The issue has been submitted to the International Court of Justice, which has deferred decision pending results of the Third UN Conference on Law of the Sea. The Greeks have not undertaken surveys in disputed areas

since 1973; the Prinos Field is well outside the zone of contention.

Outlook

Although the outlook for oil production is not as promising as earlier surveys had indicated, the government continues to assign a high priority to the search for oil in hopes of reducing its $1 billion oil import bill. At best, domestic crude production is expected to provide only 10 percent of Greece's oil requirements by 1980. To substantially improve these prospects Greece will have to attract greater interest on the part of major oil companies in exploring for offshore oil. To attract qualified companies, however, Athens will have to speed up processing of concession applications and may have to provide greater financial incentives.

JORDAN

Jordan produces no crude oil, and no commercial quantities of petroleum have been discovered despite stepped-up exploration in recent years. Amman is extremely interested in attracting foreign companies to search for oil, and there is a popular belief among Jordanians that oil can be found. Several US companies have expressed interest in searching for oil in Jordan, especially in the eastern panhandle. Pending a more thorough geophysical survey, however, Jordan's oil potential must be rated as poor. The most promising areas are on the West Bank, now controlled by Israel.

Geological Prospects

A systematic, comprehensive geological survey of Jordan has never been undertaken, although a number of partial surveys were made in the past using methods now considered obsolete. Despite the lack of information, some foreign oil companies have been willing to undertake a small exploration program. For example, under the terms of a 1975 agreement, Filon Exploration Corporation is obligated to drill at least 15 wells on an 8,400-square-kilometer area covering portions of the Jordan Valley. The company plans to drill its first well late this year. CFP and Sanyo, a Japanese firm, have expressed a desire to purchase an interest in Filon's concession. Natomas and Sun Oil are also interested in pursuing exploration programs in Jordan.

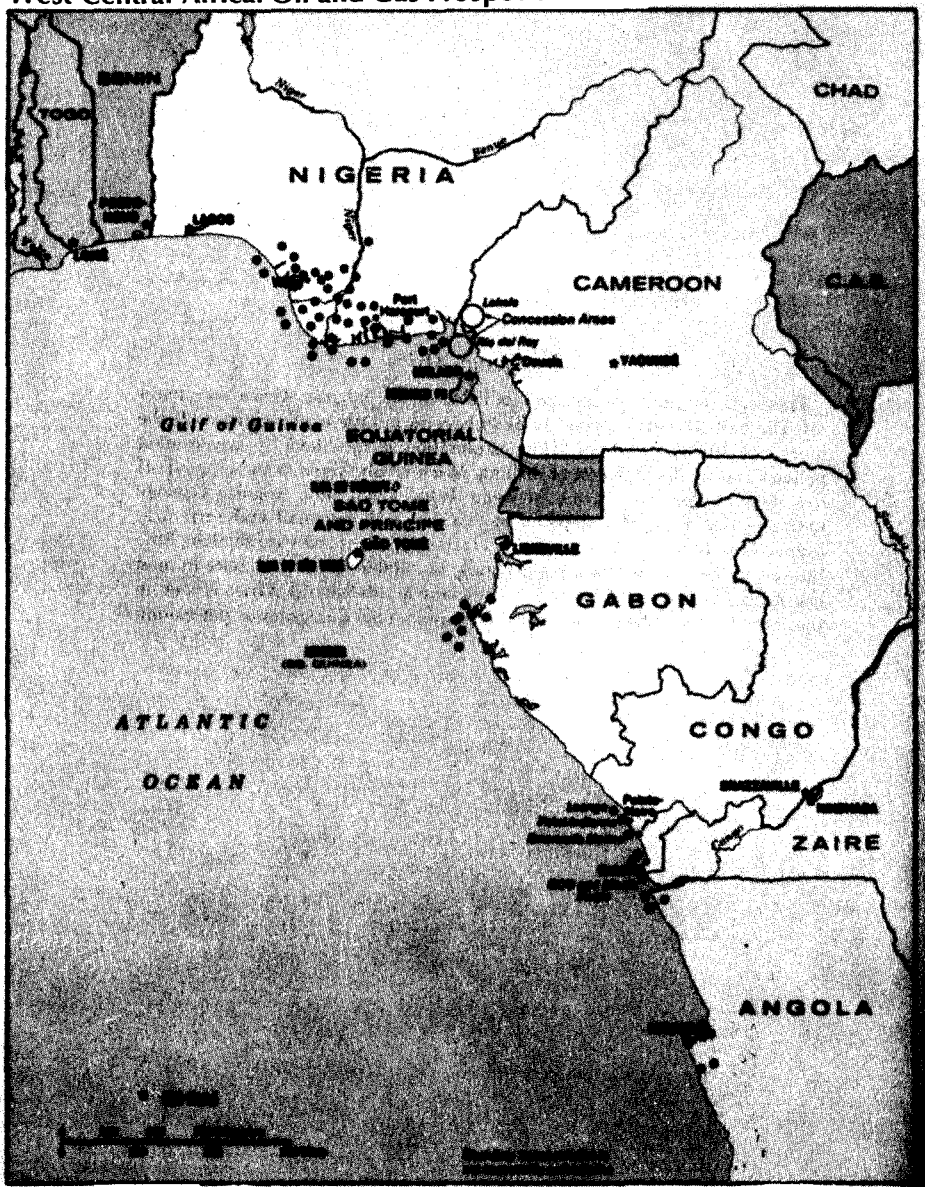
Capabilities and Constraints

Amman's stable, free enterprise system poses no problems for foreign oil companies interested in exploration in Jordan. It is rather the long history of exploratory deadends that deters further exploration. The government, by and large, has limited its involvement in oil to licensing foreign companies and awarding concessions. The only exception has been a few joint ventures involving the Jordanian National Resources Authority (NRA), which has also undertaken geophysical surveys in collaboration with US Geological Survey. Despite this activity, NRA capabilities remain limited, and dependence on external contracting for most requirements will continue.

Sub-Saharan Africa

Prospects for finding large new oilfields in sub-Saharan Africa are almost nil. The best potential appears to be in Nigeria in little explored areas off the mouth of the Niger River. Here exploration is inhibited by government policies and by the high cost of drilling. Much oil also remains to be found off the western coast of Africa between Ivory Coast and Angola. Geology indicates that most new deposits in this area will be small and extremely expensive to produce. Because of these factors, oil companies are showing little interest in these areas, despite a generally hospitable working climate in most countries. The chance of finding oil elsewhere in sub-Saharan Africa is poor; in the interior, only Chad appears to have commercial quantities of petroleum.

West-Central Africa: Oil and Gas Prospects



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NIGERIA

Nigeria has evolved from a basically agricultural country into the world's seventh largest oil producer and the second most important supplier to the United States in little more than a decade. Reserves are currently estimated at about 19 billion barrels (excluding natural gas liquid), and some promising areas have not yet been explored. Government pricing and tax policies have discouraged the new exploration and development essential to increasing capacity, however, and output has fallen.

Geological Prospects

Petroleum discovered to date in Nigeria has been of high quality, but is located in small, scattered fields, moderately deep and usually in loosely consolidated and greatly faulted sand zones. Average production per well is only about 2,500 b/d. Given these characteristics, even maintaining Nigeria's oil production requires constant investment in exploration and development. Production capacity has already fallen from 2.5 million b/d to 2.3 million b/d because of the absence of proper routine maintenance by the companies and the normal depletion of reservoirs. Although new oil continues to be found and the large potential of the Niger Delta has been barely touched, the exploration effort has slipped. In mid-1977, for example, there were only 16 active drilling rigs employed in Nigeria compared with about 30 two years earlier.

With 125 fields in operation, Nigerian oil output in June 1977 totaled about 2.2 million b/d. The largest and oldest producer with more than half Nigerian crude output is Shell-BP, a joint venture of Royal Dutch Shell and British Petroleum which began exploration in 1938 and made the first commercial discovery in 1956. All of Shell-BP's production of 1.3 million b/d comes from onshore wells. The second largest producer, Gulf Oil, produces 274,000 b/d of oil, also entirely from onshore fields. Other onshore producers are: AGIP/Phillips, 253,000 b/d; ELF, 83,000 b/d; Ashland Oil, 9,000 b/d; and Pan Ocean, 10,000 b/d. Current offshore producers are Texaco-Chevron, 55,000 b/d and Mobil, 234,000 b/d.

Capabilities and Constraints

Although Nigeria is considered one of the more moderate governments among the OPEC group, its relations with the companies have worsened during the past few years. Lagos has increased its equity in the producing companies to 55 percent, reduced production ceilings by almost 20 percent, and hiked taxes and royalties. These actions have cut sharply into company profit margins, from $1.50 a barrel in 1974 to only about 30 cents a barrel at present. The companies, contending that these returns are inadequate, are cutting back on exploration and development.

Nigeria must boost petroleum output substantially if it is to generate the revenues to meet the staggering costs of its economic and social development drive. Since Lagos cannot develop an oil industry without help from the companies, the newly created Nigerian National Petroleum Corporation (NNPC) has persuaded government leaders to offer a new incentive package to encourage exploration. The companies, however, are still awaiting clarification of several terms in the package. Even if the terms are favorable, the companies may hold back, given their mounting concern that Lagos will eventually nationalize the entire industry.

Outlook

Although geological conditions make Nigerian crude expensive to produce, there appears to be room for considerable expansion of output, particularly in the Niger Delta which has barely begun to be tapped. The pace of development will depend heavily on restoration of good rela-

tions between the companies and the government, a condition Lagos may not be willing to satisfy. The NNPC, for example, reportedly is moving to centralize indigenous oil expertise and to expand government participation in all aspects of exploration, production, and distribution. Although NNPC's low level of competence probably precludes a complete takeover of the industry anytime soon, fears that the government may be moving in this direction will continue to affect company investment decisions. The government could shorten the nationalization timetable by negotiating technical service agreements with other foreign firms.

ANGOLA

Angola, which became independent in November 1975, has considerable potential as an oil exporter. The nation's proved oil reserve base of more than 1.3 billion barrels could probably be expanded if a full-scale exploration program were undertaken. The precarious security situation and the Marxist orientation of the government make such a program unlikely in the immediate future, however. Nevertheless, the government has reached a modus vivendi with Gulf, the main company operating in the country, and undoubtedly hopes for further exploration and development to raise revenues to rebuild the sagging economy.

Geological Prospects

Angola's small Cabinda District, with offshore oil production of about 130,000 b/d, is responsible for virtually all the country's output; only 15,000 b/d come from wells located outside Cabinda, in fields operated by Texaco in Angola's northwest corner (see map, page 74). Production from Petroangol's field northeast of Luanda, which had ranged from 15,000 b/d to 30,000 b/d, has been suspended because of guerrilla activity.

Cabinda Gulf Oil Corporation—a subsidiary of Gulf Oil—began onshore exploration in 1954, but moved to more favorable offshore areas where production was begun in 1968. After being shut down from December 1975 to April 1976 because of the civil war, offshore production is now back to prewar levels. There are five producing fields offshore; no additional exploratory work is being done in the area because of the political situation. Output from the producing fields is unlikely to increase significantly until the operators feel confident enough of the political environment to make the investment required to overcome current technical difficulties.

Capabilities and Constraints

The principal current constraint to additional exploration is a lack of security and the companies' mistrust of the Marxist Angolan Government. Although maintaining or increasing oil output will no doubt remain a top economic priority, the government's tenuous control over much of the nation and its heavy dependence on Cuba and the USSR make the companies reluctant to make additional investment.

In an initial move to solidify its control over the country's oil resources, Sonangol, the state oil company, has demanded 55-percent participation in Gulf's Cabinda operations, and Gulf has little choice but to accede. Although Luanda has received advice from Nigeria and Algeria and may eventually get technical help from the USSR, it will require continued Western technical and managerial assistance in the production and refining of crude oil. The government has requested, for example, that Portuguese technicians return to Luanda to assist in operating the refinery there.

GABON

Gabon, Africa's fifth largest oil producer, has proved reserves of about 700 million barrels. Although little hope exists that major new oilfields will be discovered in Gabon, rising oil prices will make smaller finds commercially exploitable. The government, aware of the difficulties of finding and producing oil in the country, provides enough incentives to keep the interest of foreign companies now operating in the country.

Geological Prospects

Gabon's oil basin extends along Africa's west coast in a strip about 650 kilometers long and no more than 240 kilometers wide (see map, page 74). Roughly 80 percent of Gabon's fields lie offshore and are relatively small—most of the oil has been found in structures containing from 7 million to 147 million barrels. Only a few large fields have been found, notably Grondin. Gabon's crude is a fairly heavy intermediate paraffin type, with a low sulphur content.

Oil exploration in Gabon was started in 1928, but production only began in 1956. ELF-Gabon, the largest and most important company operating in the country, produces 194,000 b/d of Gabon's 220,000 b/d output. Shell-Gabon, Gulf, and 10 other foreign firms share the rest. Several of these firms are continuing exploration both onshore and offshore. The nature and location of Gabon's oil deposits make recovery difficult and expensive. The area has been extensively surveyed and, while no major new finds are likely to be found, continued small discoveries should allow output to remain close to present levels for several more years.

Capabilities and Constraints

Government participation in and direction of the oil companies has increased since Gabon's admittance to OPEC in 1973. At that time the government took 25-percent ownership in existing operations and demanded the option to buy up to 60 percent. Provisions for integrating indigenous personnel into management positions of the companies were also established. Gabon requires that 10 percent of oil company profits be invested in nonoil industrial ventures in the country. Despite these new regulations, relations between the government and the companies remain good.

CONGO

Congo, a minor oil producer and exporter, has proved reserves of about 300 million barrels. Current production consists almost entirely of low-quality oil from low-pressure offshore reservoirs; the companies hope, however, that better deposits—similar to those of neighboring Angola—may still be found. Despite its position as Africa's first "peoples republic," Congo is maintaining reasonably good relations with the operating oil companies in hopes of encouraging exploration.

Geological Prospects

Congolese oil production of about 38,000 b/d comes almost entirely from 50 producing wells in the offshore Emeraude Marine Field discovered in 1969 (see map, page 74). Congo's original producing field, Point Indienne, is largely depleted. Output at Emeraude has also begun dropping because of reserve depletion and is expected to continue its decline. National production, however, will be bolstered later this year when the new Loango Field comes on stream. Loango, discovered in 1972 and located about 40 kilometers offshore, is expected to produce about 36,000 b/d.

Development of both the Emeraude and Loango Fields has been difficult and expensive, because of their deepwater locations, low reservoir pressures, and the high viscosity of the oil. The French and Italian firms now holding concessions in the Congo currently do not plan to develop future discoveries with similar characteristics. The companies feel, however, that the Congo may have offshore oil fields similar to those in Cabinda and Gabon, where pressure and output per well are satisfactory, and plan to continue exploration.

Capabilities and Constraints

The government in Brazzaville plays no active role in petroleum matters aside from its 20-percent share of concessions held by the two foreign companies operating in the country—France's ELF and Italy's AGIP. Under terms of the concession agreements, government ownership will rise to 30 percent if production ever reaches 400,000 b/d. To keep the companies interested the Congo Government has agreed to renegotiate its taxing arrangements. Under the existing arrangement Brazzaville receives $5 per barrel, leaving the companies a 40 cents per barrel profit margin. Even if the margin were substantially increased, company interest would remain muted, given the limited geological potential of the country.

ZAIRE

Zaire joined the ranks of African oil producers in December 1975 when its two small offshore fields began commercial production. Although additional small offshore discoveries are likely, chances appear slim of finding enough oil to support a substantial increase in output, which averages 25,000 b/d. While the government has maintained an open-door policy toward foreign oil companies, the lack of promising geological structures and, to a lesser extent, Zaire's political instability have kept company interest muted.

Geological Prospects

The search for oil in Zaire began in 1958, two years before independence. In 1963 the Sorpeza group (Belgium's Fina, 50 percent; Amoco and Shell, 25 percent each) found traces of oil onshore near the Cabinda border (see map, page 74). Several oil strikes followed, but all proved to be noncommercial. A modest exploratory drilling program, based on previous seismic and preliminary work, was undertaken by Sorpeza this summer.

A group headed by Gulf Oil Corporation (with Japan's Teikouk Oil Company holding a 22-percent interest and Belgium's Societe du Littoral Zairois, Soliza, 17 percent) began drilling offshore in December 1970, striking oil with its first wildcat. Two fields—GCO and Mibale—with an estimated 200 million barrels of crude oil have now been defined and account for the bulk of Zaire's small oil production. The GCO Field is 16 kilometers from shore in 18 meters of water; the Mibale Field lies 5 kilometers from shore in 5 meters of water.

Capabilities and Constraints

The government leaves managerial and technical decisions to the oil companies, which have been unaffected by the nationalization programs in manufacturing, retailing, and agriculture. The government's main interest is in oil revenues, and it recently attempted to increase the tax on crude oil production. After the operating companies protested, a compromise was reached that speeds up payments to the government and introduces a 12.5-percent royalty payment. This should help ease the government's tight cash flow problem while maintaining sufficient incentives necessary to encourage continued exploration.